Decision 2003-086

EUB

ENMAX Energy Corporation

2004 Regulated Rate Tariff
Part A: January 1, 2004, Interim Tariff

December 5, 2003

Alberta Energy and Utilities Board

Decision 2003-086

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ALBERTA ENERGY AND UTILITIES BOARD
Decision 2003-086: ENMAX Energy Corporation
2004 Regulated Rate Tariff
Part A: January 1, 2004, Interim Tariff
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ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

ENMAX ENERGY CORPORATION
2004 REGULATED RATE TARIFF
PART A: JANUARY 1, 2004, INTERIM TARIFF

Decision 2003-086
Application No. 1306818
File No. 1210-2

1 INTRODUCTION AND BACKGROUND

With the passage of the new *Electric Utilities Act*, SA 2003, c.E-5.1 (EUA), which came into force on June 1, 2003, the municipal electric distribution systems of the Cities of Edmonton and Calgary became subject to the jurisdiction of the Alberta Energy and Utilities Board (Board). In particular, the Board became the regulatory authority for EPCOR Distribution Inc. (EDI) and ENMAX Power Corporation (EPC) for the purposes of approving distribution tariffs (DT) and regulated rate tariffs (RRT) to be effective January 1, 2004.[1]

The *Regulated Default Supply Regulation*, AR 168/2003 (*RDS Regulation*), required EDI and EPC to apply to the Board for approval of their RRTs on or before October 1, 2003.[2] The *RDS Regulation* requires the Board either to approve a final RRT for EDI and EPC to take effect on January 1, 2004, or to approve an interim RRT no later than November 30, 2003 to take effect on January 1, 2004.

Since January 1, 2001, ENMAX Energy Corporation[3] (EEC) has provided regulated rate service (formerly regulated rate option or RRO service) in the EPC service area pursuant to an arrangement between EPC and EEC approved by Calgary City Council. The Board has dealt with the requirement for Board approval of this arrangement in a later section of this Decision.

As required by the *RDS Regulation,* on October 1, 2003, the Board received Application No. 1306818 (Original Application) from EPC seeking approval on behalf of EEC of a 2004 RRT in EPC's service area.

The RRT approved by the Board for EEC will set out rates for RRT service, including energy and non-energy charges, as well as Terms and Conditions of Service (T&Cs) for all eligible customers as defined in the *RDS Regulation*.

On July 14, 2003, in anticipation of EEC's Original Application, the Board issued a notice setting out a schedule to consider EEC's RRT and a number of other matters (Notice).[4] The Notice indicated that parties interested in the Original Application should register by August 15, 2003 and that parties not registering by that date would not be updated as to any changes to the schedule of the Application.

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[1] EUA, sections 102 and 103.

[2] *DT Regulation*, section 4(1).

[3] EPC owns and operates an electric distribution system in the City of Calgary. EEC is an affiliate of EPC that provides RRT service in EPC's service territory.

[4] An EDI 2004 DT, an EPC 2004 DT and an EPCOR Energy Services Inc. (EESI) 2004 RRT

The Board established the following schedule for the Original Application:[5]

Filing of EEC Original Application	October 01, 2003
IRs to EEC	October 10, 2003
IR Responses from EEC	October 20, 2003
Interim Hearing	October 27, 2003
Oral Argument and Reply	October 30, 2003

EEC requested that if final approval of its entire RRT could not issued by November 30, 2003, then the Board should approve the Residential transition rate and issue an interim approval of the other elements of its proposed 2004 RRT. EEC indicated that the elements to be approved on an interim basis included the rates, fees, and T&Cs set out in its Original Application, a revenue requirement of $33.4 million for non-energy costs, an administration charge for residential customers, and a margin of $13.7 million applied to both energy and non-energy costs.

Under the terms of the *RDS Regulation* in force prior to November 4, 2003, only "rate classification customers"[6] (RCC) as defined in the *Regulation* could be provided a hedged transition rate beyond the end of 2003. All other eligible customers ("non-rate classification customers" or NRCC) could only receive a flow-through rate as of January 1, 2004.

On November 4, 2003, the Government of Alberta announced that it intended to extend the availability of a transition rate to ***all*** eligible customers through to June 30, 2006. On November 4, 2003, the Minister of Energy enacted the *Regulated Default Supply Amendment Regulation* by way of Ministerial Order 73/2003 (*RDS Amendment Regulation*). The effect of the *RDS Amendment Regulation* is to require an RRT provider to offer ***only*** a transition rate to all eligible customers until June 30, 2006, and to offer ***only*** a flow-through rate to all eligible customers after July 1, 2006.

On November 26, 2003, the Government of Alberta issued the *Regulated Default Supply Amendment Regulation (No. 2)* by way of Ministerial Order 80/2003 (*RDS Amendment Regulation No. 2*). Among other things, the *RDS Amendment Regulation No. 2* authorized the Board to extend the November 30, 2003 deadline prescribed in sections 3(2), 3(3)(a) and 3(4) of the *RDS Regulation* to no later than January 31, 2004. By way of letter dated November 27, 2003, the Board determined that it would extend the November 30, 2003 date specified in sections 3(2), 3(3)(a) and 3(4) of the *RDS Regulation* to Friday December 5, 2003. In the Views of Parties in this Decision, any references to a required date of November 30, 2003 should now be considered as amended to read December 5, 2003.

Pursuant to the *RDS Amendment Regulation* EEC filed a revised RRT application on November 21, 2003 (Revised Application), which included a transition rate for eligible NRCC (i.e. the small commercial, oil and gas and lighting rate classes).

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[5] The same schedule was followed for the EDI DT, EESI RRT and EPC DT applications.

[6] "Rate classification customer" is specifically defined in section 1(1)(e) of the *RDS Regulation*:
(e) "rate classification customer" means a residential rate classification customer, a farm rate classification customer, or an irrigation rate classification customer, as defined in a regulated rate tariff.

In a letter dated November 24, 2003 the Board provided notice of EEC's Revised Application and set out the following schedule that would allow the Board to issue a Decision by the legislated date of November 30, 2003:

Parties written comments	November 25, 2003 at noon
Parties written reply comments	November 27, 2003 at 9:00 am
Board Decision	On or before November 30, 2003

As noted above, the Board extended the November 30, 2003 date specified in sections 3(2), 3(3)(a) and 3(4) of the *RDS Regulation* to Friday December 5, 2003. The Board also indicated that it did not consider it necessary to re-open any of these proceedings and would issue this Decision on the basis of the record at that time.

Accordingly, for administrative purposes of this Decision, the Board considers the record to have closed on November 27, 2003. Parties participating in the proceedings are shown in Appendix 1 to this Decision.

In this Decision the Board will deal with the EEC's residential transition rate and the NRCC transition rate and all other elements of EEC's RRT to be effective January 1, 2004 on an interim basis.

In some cases, the Views of the Parties reflect submissions made at the Interim Hearing prior to the enactment of the *RDS Amendment Regulation*.

2 RESIDENTIAL CLASSIFICATION CUSTOMERS (RCC) ENERGY RATES

2.1 Introduction

In the Original Application, for RCC, EEC filed a transition rate for 2004 residential energy charges pursuant to subsection 3(4) of the *RDS Regulation*. EEC indicated that the only RCC that would be served under its RRT were residential customers since EEC does not have any farm or irrigation customers in its service area.

EEC indicated that it had used a market-based approach, through a Request for Proposals (RFP), to secure hedges for about 80% of the energy required by its residential customers and the remainder of the load was unhedged. The average price of the hedges, plus the cost of the hedge procurement and the pool trading charges was the Base Energy Price that EEC indicated constituted its fixed energy charge included in its residential transition rate. The other energy charge in EEC's proposed residential transition rate was the energy market charge/refund rate rider (EMCR), which would change quarterly to refund/collect the balance in two deferral accounts:

- The Residential Energy Deferral Account would track the value of the energy sold to or purchased from the pool to cover the long and short positions associated with the financial hedges purchased through the RFP process.
- The Residential Losses Deferral Account would track the difference between forecast and actual line losses and unaccounted for energy (UFE).

In its Revised Application, EEC noted that the fixed energy price for Commercial Customers was lower than the fixed energy price for Residential Customers as a result of the timing of the acquisition of energy. Both the previously applied for rates for the Energy Charge and Administrative Charge for Residential and Commercial Customers also changed due to consequential changes related to the amendments to the *RDS Regulation*.

To implement its residential transition tariff in its Revised Application, EEC requested approval to implement the following:

1. By November 30, 2003, a final fixed energy price of $0.05342/kWh to take effect January 1, 2004 as part of the transition rate for Residential Customers.
2. An Energy Charge for Residential Customers of $0.05905/kWh, which would be used as the interim and final Energy Charge.
3. The implementation of the Residential Energy Deferral Account and Residential Losses Deferral Account for Residential Customers.
4. Application of the quarterly adjustment mechanism (the EMCR) to Residential Customers. EMCR would recover from or refund to Residential Customers, on a quarterly basis, the net balance of the Residential Energy and Losses Deferral Accounts in addition to the 2003 fourth quarter deferral account balances and the final Energy Charge after Settlement, previously requested.

2.2 RCC Fixed Energy Charge

EEC sought final approval of a base energy price (of $0.05353/kWh) as its fixed energy charge to be included in its Residential transition rate. This base energy price was a per kilowatt-hour charge comprised of three distinct components: an energy hedge price derived from blocks of 7 by 24 base product and 6 by 16 peak product, a hedge procurement charge, and a Pool trading charge.

The fixed energy price of $0.05353/kWh per kilowatt-hour was derived as follows:

Table 1. EEC RCC Price Build-Up

			Original Application[7]	Revised Application
	Base (7x24)	**Peak (6x16)**	**Combined**	**Combined**
Energy Hedge Price	0.046951	0.068131		
Hedge Procurement Charge[8]	0.000045	0.000045		
Volume Weighted Price	0.046996	0.068176	**0.053417**	**0.053417**
			Other Energy Components	**Other Energy Components**
Combined Volume Weighted Price			0.053417	0.053417
Pool Trading Charges			0.000117	0.000117
Base Energy Price ($/kWh)			**0.053534**	**0.053534**
Margin ($/kWh)			0.003981	0.003920
Losses & UFE Charge ($/kWh)			0.001601	0.001601
Energy Charge ($/kWh)			**0.059116**	**0.059055**

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[7] Reflects errata dated October 24, 2003

[8] This number was updated in an errata dated October 24, 2003. In the Original Application it was $0.000060 /kWh

EEC included the Pool Trading Charge in the base energy price rather than in the Energy Deferral Account since EEC did not anticipate that the pool trading charge would be significantly different from the forecast $0.000117/kWh. The Board notes that the pool trading charge has since been increased from $0.000117/kWh to $0.000135/kWh.

In its Revised Application, EEC indicated that the unit price margin for Residential Customers was $0.00392/kWh for a total Energy Charge of $0.05905/kWh due to an increase in the total margin required as a result of the *RDS Amendment Regulation*.

The Board will deal with the appropriate interim return margin in a later section of this Decision.

2.2.1 Views of the Applicant

EEC indicated that the prices derived from the RFP were market-based prices derived from a fair and transparent process.

2.2.2 Views of the Interveners

Calgary

Calgary accepted that the prices derived in the 2004 RFP were representative and appropriate for the Board to approve. In Calgary's view market transactions had occurred and Calgary did not propose to recommend a change to the results. Calgary was encouraged with a seemingly open and well-conducted RFP. Calgary agreed that the result was reasonable under the circumstances and, indeed, may have been characterized as a good result. Consequently, Calgary did not request any change in the hedge procurement results, but instead focused on future improvements to the RFP process that might lead to even better results for next year's procurement.

Calgary accepted that EEC has identified the total costs incurred in its hedge procurement process and has demonstrated that it would recover these costs through an appropriate allocation of the costs between Calgary and the other RRT customers, as indicated in EEC's response CAL-EPC(RRT)-2.

Calgary had no objection to a Pool trading charge of $0.000117/kWh being included in the base energy. Calgary noted EEC's indication that it is prepared to maintain the charge as filed on a final basis.[9]

The fixed final energy component of that transition rate has to be determined by the Board on a final basis as of November 30, 2003. Calgary took the position that it was not necessarily the case that the November 30, 2003 date applied with respect to procuring a hedge. Calgary wondered whether an RRT provider could get a hedge approved for a transition rate under Section 2(2) of the *RDS Regulation* after November 30, 2003.

Calgary submitted that EEC would be guaranteed full recovery of its hedge procurement costs incurred on behalf of residential customers, through the hourly energy deferral account.

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[9] TR page 315

CCA

The CCA fully supported the views expressed by Calgary.

2.2.3 Views of the Board

In regard to the energy procurement undertaken for Residential RRT customers for 2004, the Board notes that no intervener has indicated that it objects to the resulting base energy price derived even after the passage of the *RDS Amendment Regulation*. Further, there is evidence that the RFP was conducted in a fair and transparent manner and resulted in a market-based price for the energy acquired. That evidence includes the involvement of the independent market expert hired by EEC to plan and oversee the RFP.

The Board notes that there was considerable testing of the RFP process and results through the IR process that appears to have satisfied any intervener concerns regarding the 2004 RFP results.[10] The Board has also examined the RFP methodology set out in the Original Application as well as the IR responses and is satisfied that the RFP resulted in a market based price for the hedge portfolio designed by EEC for its residential customers. No intervener has objected to the approval of the fixed energy charge component of EEC's Residential transition rate.

For these reasons, the Board is comfortable approving the costs of the energy acquired through the residential RFP to be included as the fixed cost portion of the residential transition rate as proposed by EEC. However, for the reasons set out below in Section 7, the Board is only comfortable doing so for the first quarter of 2004.

Accordingly, the Board approves the fixed energy charge component of EEC's RCC rate of $0.05353/kWh on a final basis for the first quarter of 2004.

Adding the interim margin of 2% that the Board has approved later in this Decision and the forecast Losses and UFE charge results in a total Residential Energy Charge of $0.05620/kWh as shown below:

Table 2. Board Approved RCC Interim Energy Charge

	Board Approved
Base Energy Price ($/kWh)	**0.05353**
Margin ($/kWh)	0.00107
Losses & UFE Charge ($/kWh)	0.00160
Energy Charge ($/kWh)	**0.05620**

Accordingly, the Board approves an interim, refundable Residential Energy Charge of $0.05620/kWh effective January 1, 2004.

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[10] However, interveners did express concern about the RFP process for 2005 as described later in this Decision.

2.3 RCC Deferral Accounts and Adjustment Rider

EEC proposed two energy deferral accounts, each of which would carry forward a credit or refund from the fourth quarter of 2003 calculated based on the methodology approved by the EURC. The two deferral accounts were:

- The Energy Deferral Account, and
- The Losses Deferral Account.

The amounts in each of the deferral accounts would be charged or refunded, with four adjustments throughout the year, via the Energy Market Charge/Refund Rate Rider (EMCR), described below.

EEC proposed that it would maintain the Energy Deferral Account and the Losses Deferral Account and the quarterly refund of those balances based on initial settlement.

The Energy Deferral Account

EEC indicated that the actual physical energy would be purchased from the Power Pool at the Power Pool's hourly spot price. The financial benefit or cost from the Base and Peak hedges would be added to the physical energy costs. A financial benefit would, in effect, reduce the physical costs, while a financial cost would, in effect, increase the physical costs. The combination of the physical purchase costs and hedge costs/benefits would be the supply cost for the Residential Customers.

Since customers would be billed the fixed Base Energy Price for their energy usage, a reconciliation of the supply costs to that rate would be required. The Energy Deferral Account would be used to perform this reconciliation.

The following formula would be used to calculate, on an hourly basis, the amount that would be placed in the Energy Deferral Account:

Hourly Deferral = ((Pool Price + Trading Charge) x Usage) + ((VWBP – Pool Price) x 7x24
Hourly Deferral = ((Pool Price + Trading Charge) x Usage) + ((VWBP – Pool Price) x 7x24
where, Pool Price = hourly price as posted ($/kWh)
Trading Charge = $0.000117/kWh

Where:

Usage = aggregate consumption as per initial monthly settlement data
VWBP = $0.046996 per kWh
7x24 Hedge Volume = 172,727 kW of base secured in RFP
VWPP = $0.068176 per kWh
6x16 Hedge Volume = 133,938 kW of peak secured in RFP, only accounted for if hour is on-peak
Base Energy Price = $0.053534[11] per kWh

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[11] After errata dated October x, 2003. Prior to errata $0.053567 per kWh.

The Losses Deferral Account

Customers would initially be charged $0.00160/kWh on metered consumption for losses and UFE. The adjustments would be calculated based on initial monthly settlement dated one month after the three-month period ends calculated, on an hourly basis, as follows:

Losses Deferral Account Balance = (Losses & UFE Volume)X(Pool Price +Trading Charge) -Usage X Losses & UFE Charge

Where:

Losses & UFE Volume = Residential Customer Usage X Losses & UFE Rate
Pool Price = hourly pool price
Trading Charge = $0.000117/kWh
Losses & UFE Charge = $0.00160/kWh
Usage = aggregate Zone consumption as per initial monthly settlement data

Energy Market Charge/Refund Rate Rider (EMCR)

The balances accounted for and tracked through the deferral accounts would be passed on to Residential Customers, with four adjustments throughout the year, via the EMCR. The adjustment would be calculated based on Initial Monthly settlement data, and performed one month after the three-month period ends, to ensure the settlement data was available. The EMCR for the subsequent three months would be calculated as:

EMCR = (a)/(b)

Where:

(a) = the sum of balances in the Energy and Losses Deferral Account for the calculated three months, and
(b) = the estimated Residential Load (kWh) forecast by EEC for the next three months.

EEC indicated that it would use this quarterly adjustment mechanism for truing-up the Energy Charge component to market conditions. The EMCR would recover from or refund to Residential Customers, on a quarterly basis, the net balance of the Energy and Losses Deferral Accounts, the 2003 fourth quarter deferral account balances and the final Energy Charge after Settlement. The reconciliation of the difference between initial and final settlement for each month in 2003 as prescribed by EURC would start in July 2004 and continue until total balances relating to the 2003 reconciliation to final settlement are returned to zero.[12]

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[12] BR-EEC (RRT) 4(b)

2.3.1 Views of the Applicant

In response to Calgary's indication that settlement on initial data is not appropriate, EEC indicated that using final settlement data could create a lag of up to seven months. EEC submitted that that lag might lead to more concerns that the true-up may miss customers who received RRT service during the quarter being trued up and subsequently leave RRT service during the lag period. Further, there had been no suggestion that the use of final data would create an appreciable difference. While EEC indicated that final settlement data could be used, EEC considered it was important that the implications of that lag be understood.

2.3.2 Views of the Interveners

Calgary

Calgary did not oppose the approval and establishment of the applied-for deferral accounts in the interim tariff, given that the details of the deferral accounts would be reviewed during the final tariff portion of this proceeding. However, Calgary submitted that for the purposes of the interim tariff, the energy deferral account and the losses deferral account should be based on a true-up using the final settlement data as approved by the EURC for 2003. The final form of the deferral accounts could be addressed during the final tariff portion of this proceeding.

Calgary noted that the first quarterly adjustment for the EMCR is expected to be billed on April 1st, 2004 and that EEC does not have any plans to submit to the Board information supporting the quarterly adjustments to the EMCR.[13] Calgary submitted that for the purposes of the interim tariff, the current reporting requirement as approved by the EURC for 2003 should be used. That requirement is set out on page 33 of the EURC Decision. The final reporting format and requirement can be addressed during the final tariff portion of this proceeding.

PICA

PICA accepted EEC's proposal to assume any risk related to the difference in consumption between initial and final settlement for purposes of establishing 2004 interim rates.

PICA also accepted the EEC use of customer class specific load profiles to weight Pool prices to reflect hourly consumption for customers without interval metering.

2.3.3 Views of the Board

On an interim basis, the Board accepts the general approach that EEC has proposed to maintaining the Energy Deferral Account and the Losses Deferral Account and the quarterly collection/refund of balances in those accounts for the first quarter of 2004. The Board will deal with the 2004 period beyond the first quarter later in this Decision.

However, the Board notes EEC's indication that it has no intention to provide justification of the quarterly change to the EMCR to the Board prior to implementation of the change. The Board considers that it would be inappropriate for EEC to change its EMCR without a filing to the Board with justification for the change in its EMCR, including full disclosure of the calculations supporting the adjustment. The Board also considers that it would be appropriate for EEC to file the justification for any EMCR using the current reporting requirement as approved by the

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[13] CAL-EPC(RRT) 37

EURC for 2003. The Board considers that the need for any change to that reporting requirement or further reporting or audit may be tested during the final tariff portion of this proceeding.

Accordingly the Board directs EEC to file for acknowledgement the justification for each quarterly adjustment to its RCC EMCR, including full disclosure of the calculations supporting the adjustment using the current reporting requirement as approved by the EURC for 2003 before the change in the RCC EMCR is made.

The Board also considers that, for consistency in reporting and for the purposes of the interim tariff, the Energy Deferral Account and the Losses Deferral Account should be based on a true-up using the final settlement data as approved by the EURC for 2003. The final form of the deferral accounts and reporting requirements may be addressed during the final tariff portion of this proceeding.

2.4 RCC RFP Process Concerns

EEC indicated that the Residential RFP attracted multiple energy marketers by keeping volume blocks in small increments (5 MWh). When procuring the hedges for City of Calgary customers, EEC also procured hedges for other municipalities where EEC provides regulated services.

The RFP process consisted of a pre-qualification process wherein energy marketers were required to establish credit arrangements prior to the RFP. An independent energy market expert oversaw the RFP process. The expert indicated that the RFP pre-qualification process and the RFP process was fair to all counter parties and stakeholders and provided EEC with a competitive market price for the fixed price portion of its RRT.

Since ENMAX Energy Marketing Inc. (EEMI), an affiliate of EEC, would likely bid to supply product in the RFP, a conflict screen was set up between EEMI and EEC as part of the RFP process to ensure those who were working on the RFP did not communicate with those preparing the EEMI bid. Those working on the EEMI bid were similarly prevented from communicating with those working on the RFP for EEC. The conflict screen was described in detail in Appendix "D" of the Original Application.

2.4.1 Views of the Applicant

EEC noted that while Calgary did not have any problem with the result of the RFP, Calgary submitted that a number of areas of the RFP could be improved. EEC submitted that Calgary's submissions were opinions without evidence to support them.

EEC reiterated that it had retained an independent third party expert to ensure that not only the process was fair, but also that it was market based and ensured that market prices resulted. The expert had indicated that he was satisfied that it was an appropriate and transparent process, and that the result was a good result in the circumstances

2.4.2 Views of the Interveners

Calgary

Calgary accepted that the prices derived in the 2004 RFP were representative and appropriate for the Board to approve. However, Calgary had concerns about the fairness, transparency, and prudence of future energy procurement strategy and practice. Calgary had a number of suggestions for improvement of EEC's procurement plans for 2005 in the areas of load forecast, block sizes, and the RFP process. Calgary did not make any submission to change the amounts procured in the 2004 residential RFP.

Calgary considered that the load forecast was overly pessimistic, that EEC should include price as a determinant in the determination of block sizes and that the RFP process could be improved.

With respect to block sizing, Calgary's principal concern on the hedge procurement side was with the methodology EEC used to design and acquire the hedge portfolio. Calgary submitted that using only three objectives left a critical objective missing, which would have been to achieve the three stated objectives while attempting to minimize the cost exposure of the RRT customers.

Calgary was concerned that the definition of the risk to be mitigated through hedging, by fixing a price for a specific block of both base load and peak energy, has changed significantly since EEC's 2003 RRO application before the EURC. As is stated on page 8 of the EURC Decision, the size of the base load the and on-peak block sizes were based on mitigating risk as measured in terms of the RRT customer's value at risk, or VAR, which is a statistical maximum dollar exposure to Pool prices.

However, in 2004, EEC has selected the block sizes based on volumetric risk, without attaching any price assumptions or cost consequences to those volumes of energy that will be exposed to the Pool price. EEC's inability to carry out a VAR analysis was attributed to the conflict screen set up between EEMI and EEC as part of the RFP process[14].

Calgary submitted that EEC has the tools available to include price as a factor, and thus EEC has the onus to perform an appropriate VAR analysis in deriving the most appropriate block sizes to hedge on behalf of residential RRT customers.

The conflict screen should not preclude EEC from using the necessary tools available to either it or, indeed, to EEMI to serve the best interests of the residential RRT customers. Calgary submitted that it is impossible to determine whether the chosen block sizes will actually mitigate the dollar cost exposure of the residential RRT customers if hourly Pool price assumptions are precluded.

Calgary recognized that fixing the cost on any reasonable load-related basis, would, by definition, reduce the volumetric exposure of RRT customers to Pool prices. However, Calgary submitted that, without an underlying forecast of spot energy prices, it is impossible to determine the relative merits of one combination of block sizes compared to any other combination in terms of the total cost of the hedged blocks and the resultant potential cost exposure of RRT customers to Pool prices.

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[14] Transcript Volume 2, page 342

Calgary also noted that the RFP was limited to just one-year 7 by 24 products and one-year 6 by 16 products. Calgary noted that there are other products available on the Alberta market, such as monthly products, quarterly products, and super-peak products that EESI intends to procure. Calgary submitted that in the future, EEC should investigate the benefits of using a wider range of products, especially those with greater liquidity or that better match the Calgary RRT load profile. Given that EEC carried out a single RFP transaction, Calgary submitted that EEC should investigate whether there may be price benefits to residential RRT customers from holding more than one RFP that outweigh the costs of conducting the additional RFPs.

CCA

The CCA fully supported the views expressed by Calgary. The CCA also submitted that RRT providers should consider the timing of the procurement of their energy portfolios for RRT load to ensure that they are not competing against one another and driving up prices. The CCA requested that, if possible, the Board should provide some direction to parties in that regard.

2.4.3 Views of the Board

The Board notes the Calgary and CCA suggestions for improvement of future energy procurement by EEC. The Board considers that it would be appropriate for EEC, like EESI and EPCOR Energy Services (Alberta) Inc. (EESAI), to discuss with interveners the procurement of a hedge portfolio. However, the Board recognizes that the 2004 timelines somewhat restricted the possibilities for discussion with customer representatives.

Specifically, it appears to the Board that the following suggestions made by Calgary have merit in determining appropriate EEC RRT energy portfolios:

- The appropriate sizing of energy blocks to be hedged for RRT purposes should consider reducing RRT customers' potential cost exposure to Pool prices, not just to volume exposure.
- Consideration of other products available on the Alberta market, such as the monthly, quarterly and super-peak products along with the one-year 7 by 24 and one-year 6 by 16 products included in the EEC RFP.
- Investigation of whether there may be price benefits to residential RRT customers from holding more than one RFP that outweigh the costs of conducting the additional RFPs.

Later in this Decision the Board has directed EEC to discuss the RCC and NRCC energy plans with EEC's customers.

3 NON-RATE CLASSIFICATION CUSTOMERS (NRCC) ENERGY RATES

3.1 Introduction

The *RDS Amendment Regulation* resulted in a requirement for considerable change to the energy portion of EEC's Application. The Original Application was filed under the *RDS Regulation,* at which time, while both RCC (residential customers) and NRCC (small commercial customers) were eligible for RRT service, small commercial customers were only eligible for a flow-through energy rate.

Accordingly, EEC indicated in the Original Application that it would provide the flow-through rate required under the *RDS Regulation* for small commercial customers.

In its Revised Application, EEC indicated that it had used a market-based, RFP approach to secure hedges for about 92% of the energy required by its commercial customers and the remainder of the load was unhedged. The average price of the hedges, plus the cost of the hedge procurement and the pool trading charges was the Base Energy Price that EEC indicated constituted its fixed energy charge included in its commercial transition rate. The other energy charge in EEC's proposed commercial transition rate was the energy market charge/refund rate rider (EMCR), which would change quarterly to refund/collect the balance in two deferral accounts:

- The Commercial Energy Deferral Account would track the value of the energy sold to or purchased from the Power Pool to cover the long and short positions associated with the financial hedges purchased through the RFP process.
- The Commercial Losses Deferral Account would track the difference between forecast and actual line losses and unaccounted for energy (UFE).

EEC noted that the fixed energy price for Commercial Customers was lower than the fixed energy price for Residential Customers as a result of the timing of the acquisition of energy. Both the previously applied for rates for the Energy Charge and Administrative Charge for Residential and Commercial Customers also changed due to consequential changes related to the amendments to the *RDS Regulation.*

To implement its NRCC transition tariff in its Revised Application, EEC requested approval to implement the following:

1. By November 30, 2003, a final fixed energy price of $0.05161/kWh to take effect January 1, 2004 as part of the transition rate for Commercial Customers.
2. An Energy Charge for Commercial Customers of $0.05719/kWh, which would be used as the interim and final Energy Charge.
3. The implementation of the Commercial Energy Deferral Account and Commercial Losses Deferral Account for Commercial Customers.
4. Application of the quarterly adjustment mechanism (the EMCR) to Commercial Customers. The EMCR would recover from or refund to Commercial Customers, on a quarterly basis, the net balance of the Commercial Energy and Losses Deferral Accounts in addition to the 2003 fourth quarter deferral account balances and the final Energy Charge after Settlement, previously requested.

3.2 NRCC Fixed Energy Charge

In its Revised Application, EEC sought final approval of the base energy price (of $.0.05173/kWh) as its fixed energy charge to be included in its Commercial transition rate. This base energy price was a per kilowatt-hour charge comprised of three distinct components: an energy hedge price derived from blocks of 7 by 24 base product and 16 by 16 peak product, a hedge procurement charge, and a Pool Trading Charge.

The fixed energy price of $.0.05173/kWh was derived as follows:

Table 3. EEC NRCC Price Build-Up

	Base (7 x 24)	Peak (6 x 16)	Combined
Energy Hedge Price	0.04804	0.06244	
Hedge Procurement Charge	0.00003	0.00003	
Volume Weighted Prices	0.04807	0.06247	0.05161
			Rate Design
Combined Volume Weighted Price			0.05161
Pool Trading Charges			0.00012
Base Energy Price ($/kWh)			**0.05173**
Margin ($/kWh)			**0.00392**
Losses/UFE Charge ($/kWh)			**0.00155**
Energy Charge ($/kWh)			**0.05719**

EEC included the Pool Trading Charge in the base energy price rather than in the Energy Deferral Account since EEC did not anticipate that the Pool Trading Charge would be significantly different than forecast.

In its Revised Application, EEC indicated that the unit price margin for Commercial Customers was $0.0392/kWh for a total Energy Charge of $0.05719/kWh due to an increase in the total margin required.

The Board will deal with the interim margin later in the Decision.

3.2.1 Views of the Applicant

EEC indicated that the prices derived from the RFP were market-based prices, derived from a fair and transparent process.

EEC noted that with the imposition of a very tight timeline on all parties by the *RDS Amendment Regulation*, to assist the Board and all parties, on November 14, 2003 EEC provided all interested parties with a letter that set out in as much detail as was possible in the circumstances, the revisions to the Original Application that EEC intended to make. In the letter, EEC invited parties with any questions to contact EEC and invited interested parties to submit comments regarding EEC's proposed approach. No interested parties, including PICA, contacted EEC with either questions or comments regarding EEC's proposed approach.

EEC submitted that it relied at least in part on the lack of feedback received from interested parties when it proceeded in the manner outlined in its November 14, 2003 letter. EEC was disappointed by PICA's written comments, which were sharply critical of certain aspects of EEC's Revised Application that were clearly outlined in EEC's November 14, 2003 letter, and in respect of which EEC received no questions or comments from PICA.

While PICA stated that there was insufficient time to test the Revised Application through IRs, either informally or formally, EEC noted that PICA made no request for information from EEC, either after receiving the November 14, 2003 letter, or after the Revised Application was filed.

EEC submitted that the approach taken by EEC in securing an energy supply and designing a NRCC transition rate was the same as the approach taken by EEC for Residential Customers. The approach was tested, both through written IRs and oral cross-examination at the hearing. Interested parties were also given the opportunity to present oral argument on EEC's approach. This shared approach includes the RFP process and methodology and the use of Peak and Base hedges. Calgary stated that the RFP was "…seemingly open and well-conducted."[15]

EEC submitted that PICA's claim that the "applications are untested" was, at best, overstated. The common approach used was tested through a complete hearing process that afforded all interested parties a fair and reasonable opportunity to test EEC's 2004 RRT Application. The overwhelming majority of EEC's costs had not changed, and were tested in the interim hearing. EEC strongly disagreed with PICA's claims that the costs set out in the application are "unsubstantiated and unsupported."

In response to PICA's suggestion that EEC should procure its energy quarterly, rather than procuring the energy in a single tranche, EEC submitted that it was not clear that procuring energy through several processes during 2004 would comply with the requirements of the legislation. EEC submitted that PICA had notice of the manner by which EEC proposed to procure energy for NRCC and expressed no concerns with that manner or process, either in the interim hearing, or before the RFP was held. EEC has now purchased energy for 2004, through a market-based RFP, to provide service to NRCC under a transition rate.

Further, EEC submitted that it was not clear that procuring energy quarterly would result in lower prices since, in spite of the fact that the market was well aware of the timing imposed by that *RDS Amendment Regulation*, the hedges secured for the NRCC through the second RFP was less expensive than the hedges secured through the first RFP. The un-contradicted evidence of Mr. Joyce was that EEC's RFP process was fair to all parties and resulted in a competitive market price for the fixed price portion of the RRT. EEC followed the same process for the second RFP as it did for the first.

In response to PICA's view that a collaborative process might result in a change in EEC's 2004 acquisition practices and hedged energy charge, EEC indicated that the hedges for 2004 have already been acquired from a number of parties through market-based RFP processes. Even if EEC were to agree to modify its acquisition practice, the market-based RFP results for 2004 would remain unchanged. Furthermore, in Decision 2003-096, the Board refused to permit EEC to commence a negotiated settlement process for its 2004 DT and RRT. EEC submitted that the option of a collaborative process was not open to EEC for its 2004 RRT.

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[15] Interim hearing transcript, page 826.

In response to PICA's suggestion that the fixed energy charge proposed by EEC be approved only for the first quarter of 2004, EEC noted that the hedges for 2004 have been acquired and that the Board must approve the fixed energy charge by November 30, 2003.

In response to PICA's objection to approval of the hedge procurement charge, EEC indicated that the hedge procurement charge for the second RFP was calculated in the same manner as the hedge procurement charge for the first RFP.

In response to PICA's claim that there is no evidence regarding the decline in customer numbers, EEC submitted that the Original Application contained evidence justifying EEC's forecasts, and PICA was provided with the opportunity to test this evidence during the interim hearing. Further, the Revised Application provided evidence of the reasons for the revision of EEC's forecast.

In response to PICA questions of whether EEC's evidence of 92% coverage for NRCC meant annual, quarterly, monthly or hourly coverage, EEC submitted that it had procured energy for all of 2004, and the stated coverage was on the same annual basis.

EEC submitted that PICA's indication that the unhedged portion of the NRCC load appeared to include a substantial amount of peak energy was incorrect. EEC submitted that the hedges for NRCC and Residential Customers were procured on the same basis and there is more hedge coverage during peak periods than in non-peak periods. As set out in Table 3.3 on page 10 of the Revised Application, EEC's long position for NRCC exceeds its short position, during peak periods.

In response to PICA suggestions that conflict screens and confidentiality provisions are of "little comfort", EEC noted that, while all parties had an opportunity to test the sufficiency of the measures put in place by EEC in respect of the first RFP through IRs and in the interim hearing, the adequacy of these measures was not challenged. They were also reviewed and approved by an independent third party, Mr. Joyce.

EEC objected most strongly to PICA's suggestion that EEC and its affiliates will behave inappropriately. EEC submitted that PICA's comment ignored the fact that the Board has already determined that EEC's proposed Inter-affiliate Code of Conduct will be implemented on January 1, 2004.

3.2.2 Views of the Interveners

CCA

The CCA supported the views of PICA.

PICA

PICA had a number of concerns with the way the NRCC base energy price was achieved.

PICA submitted that, had the *RDS Amendment Regulation* been enacted earlier in the year, NRCC and RRT providers might have been able to develop and test appropriate hedging mechanisms in a reasonable and appropriate manner. Instead the timing effectively set NRCC back to late 2000 and once again forced NRCC to try and address eleventh hour applications with monumental cost ramifications. While PICA recognized that the utilities were also forced to deal with unreasonably short time lines, PICA submitted that it is the customers who ultimately bear the costs of whatever solution is developed.

PICA submitted that, as the level and volume of coverage is an issue yet to be determined on a final basis, any energy charge established should be only for the first quarter of 2004, permitting further review either through a formal process or, preferably, as part of a consultative process in the next few months.

PICA submitted that as energy demands fluctuate over the course of the year, it is likely the use of various term energy products would allow a closer match to load. PICA noted that the fixed energy charge for EESI and EESAI for both RCC and NRCC was proposed to be established quarterly. PICA submitted that, if further review or a collaborative process results in a change in EEC's acquisition practices, the hedged energy charge should also change. In PICA's view, if an agreement was not reached before March 1, 2004, the first quarter energy price could be carried forward for a further three-month period.

While PICA had concerns with the prudence of EEC's acquisition methods, it did not consider the resultant rate to be substantially out of line with the rates proposed by other utilities for the same period. PICA submitted that the fixed energy charge of $0.05161/kWh proposed by EEC could take effect January 1, 2004, for the first quarter of 2004. However, PICA submitted that the hedge procurement charge included as part of EEC's calculation of the fixed energy charge should only be approved on an interim basis and be reviewed as part of the final proceeding.

PICA also submitted that the forecast volumes might be understated to a considerable degree and that may have significant ramifications in terms of customer exposure for unhedged volumes. While EEC increased its customer retention levels, forecast volumes for commercial customers appeared to be based on its initial projection of customer numbers. PICA noted that there had not yet been any testing of the customer numbers or forecast volumes as the Original Application contemplated a flow through rate. PICA submitted that there was no evidence justifying the decline in customer numbers suggested by EEC by indicating that customer retention rates will be significantly different than in the previous few years or that customer growth will be any less an offsetting factor to customer declines.

PICA noted that if the forecast volumes are understated, EEC may not have the forecast coverage of 92%. PICA also submitted that it was unclear whether 92% coverage referred to annual, quarterly, monthly or hourly coverage as customer loads will vary throughout the day and year.

In PICA's view, in the absence of any further evidence and review, it was unclear whether EEC's proposal began to fulfil the requirements of the *RDS Amendment Regulation* and provided adequate hedge protection to customers.

It appeared likely to PICA that some of the periods not covered by hedges were peak periods, when prices are likely to be most volatile and the potential downside for customers greatest. Consequently, even if 8% of the volume is unhedged, the costs associated with those unhedged volumes may be far greater than 8%. The portion left unhedged appeared to include a substantial amount of peak energy products, likely to be those volumes required during super peak periods. As these tend to be the highest priced and most price volatile hours in the Power Pool, customers are faced with a considerable amount of risk.

PICA also submitted that it was unreasonable and imprudent to use a single RFP for the purchase of all or a large portion of hedges for the NRCC load. In PICA's view, seeking a large quantity of energy on a single day may give rise to artificially high prices as the market responds to the apparent and increased demand. The acquisition of the entire portfolio during one day of the year did nothing to mitigate or spread customer risk. Acquiring volumes over an extended or ongoing period and for different periods (i.e. annual, quarterly and monthly products) should provide a better indication of the market on an ongoing basis, rather than energy price signals based on one day in the market.

Because EEC's hedges are based on untested volume and customer forecasts and EEC's portfolio appears limited in the types and terms of contracts, PICA considered it possible that there may be several hours when EEC will be significantly over or under hedged.

PICA was particularly concerned about EEC purchases from its affiliate, EEMI, that result in an over-hedge. PICA expected the greatest level of over-hedges to occur during off peak hours, when there is a greater probability that any resale of the energy would be at less than the original purchase price. If EEC purchased unnecessary volumes from EEMI, EEC's affiliate would have gained through EEC's conduct, at the ultimate expense of customers. PICA submitted that in the absence of any independent review of forecast volumes, affiliates should not be permitted to participate in any procurement activities.

To maximize bidders and avoid unnecessarily limiting affiliates from RFPs, PICA submitted that such transactions should be considered as part of the final proceeding having regard to the reasonableness of the underlying volume forecasts used in establishing the RFP requirements. Any risk regarding prudence or reasonableness of the transactions should rest with EEC, who undertook such actions in the absence of any consultation with customers or approval by the Board.

PICA also submitted that there should be some audit and/or review provisions applicable to these affiliate transactions to permit independent oversight of the process. PICA considered conflict screens and confidentiality provisions to be of little comfort as breaches are difficult to prove and the consequences hard to quantify. Arguably, such provisions are useless unless there is some risk and costs associated with the breach of them. PICA submitted that a better safeguard would be the approval of forecast volumes by customers and/or the Board and the implementation of an audit provision to be utilized, as required.

PICA submitted that EEC's procurement policies and the resulting energy charges needed to be addressed through a formal process, allowing the Board and customers a reasonable opportunity to test the application and, where appropriate, file evidence or otherwise make submissions concerning their prudence. In PICA's submission, this kind of review was only possible if the acquisition process and resulting energy charge were addressed as part of the final proceeding.

CCG

The CCG shared PICA's view that the use of a single RFP was not the best means of managing the financial risk associated with the energy to be provided under a transition rate. Without accepting the "unreasonable and imprudent" characterization of EEC's procurement method, the CCG agreed with PICA's suggestion that the process should be tested in the final proceeding.

3.2.3 Views of the Board

In regard to the energy procurement undertaken for NRCC for 2004, the Board notes that no intervener has objected to the resulting base energy price being implemented January 1, 2004. Further, there is persuasive evidence that the RFP was conducted in a fair and transparent manner and resulted in a market-based price for the energy acquired. That evidence includes the involvement of the independent market expert hired by EEC to plan and oversee the RFP.

Later in this Decision the Board has directed EEC to discuss the RCC and NRCC energy plans with customers. On this basis, the Board is comfortable approving the costs of the energy acquired through the NRCC RFP to be included as the fixed cost portion of the commercial transition rate as proposed by EEC. However, for the reasons set out in Section 7 of this Decision, the Board is comfortable doing so only for the first quarter of 2004.

Accordingly, the Board approves the fixed charge component of EEC's NRCC transition rate of $0.05173/kWh for the first quarter of 2004.

Adding the interim margin of 2% that the Board has approved later in this Decision and the forecast Losses and UFE charge results in a total Commercial Energy Charge of $0.05432/kWh as shown below:

Table 4. Board Approved NRCC Interim Energy Charge

	Board Approved
Base Energy Price ($/kWh)	**0.05173**
Margin ($/kWh)	0.001035
Losses & UFE Charge ($/kWh)	0.001600
Energy Charge ($/kWh)	**0.05437**

Accordingly, the Board approves an interim, refundable Commercial Energy Charge of $0.05437/kWh effective January 1, 2004.

3.3 NRCC Energy Deferral Accounts and Adjustment Rider

3.3.1 Views of the Applicant

In its Revised Application, EEC proposed two Commercial deferral accounts:

- The Energy Deferral Account, and
- The Loses Deferral Account.

The mechanism and function of each of deferral account would be the same as for the corresponding Residential deferral accounts, including the true-ups related to 2003 as summarized earlier in this Decision. Only the forecast Losses and the value of the energy used in the respective energy deferral accounts would differ.

3.3.2 Views of the Interveners

CCA

The CCA supported PICA's views on these issues.

PICA

PICA submitted these proposed Deferral Accounts represented another risk borne by customers. In the absence of any testing, PICA submitted that the forecast line losses and UFE should be approved on an interim refundable basis. The reasonableness of the forecasts requires further review as part of the final proceeding.

3.3.3 Views of the Board

On an interim basis, the Board accepts the general approach proposed by EEC to maintain the Energy Deferral Account and the Losses Deferral Account and the quarterly collection/refund of balances in those accounts for the first quarter of 2004. The Board will deal with the period beyond the first quarter of 2004 later in this Decision.

However, the Board notes EEC's indication that it has no intention to provide justification of the quarterly change to the EMCR to the Board prior to implementation of the change. The Board considers that it would be inappropriate for EEC to change its EMCR without a filing to the Board with justification for the change in its EMCR, including full disclosure of the calculations supporting the adjustment. The Board also considers that it would be appropriate for EEC to file the justification using the current reporting requirement as approved by the EURC for 2003. The Board considers that the need for any change to that reporting requirement or further reporting or audit may be tested during the final tariff portion of this proceeding.

Accordingly the Board directs EEC to file for acknowledgement the justification for each quarterly adjustment to its NRCC EMCR, including full disclosure of the calculations supporting the adjustment using the current reporting requirement as approved by the EURC for 2003 before the change in the NRCC EMCR is made.

The Board also considers that, for consistency in reporting for the purposes of the interim tariff, the Energy Deferral Account and the Losses Deferral Account should be based on a true-up using the final settlement data as approved by the EURC for 2003. The final form of the deferral accounts and reporting requirements may be addressed during the final tariff portion of this proceeding.

4 ADDER IN LIEU OF RECORD OF RCC AND NRCC DEFERRAL ACCOUNTS

4.1 Views of the Applicant

EEC's 2004 RRT Application includes the use of deferral accounts to manage financial risk associated with the electric energy supply required to meet the obligation under its transition rate. In EEC's view, the use of such deferral accounts complies with subsection 5(2) of the *RDS Regulation*, which was added by the *RDS Amendment Regulation*. If the Board is not convinced of EEC's view of subsection 5(2), EEC requested approval of an alternative transition rate structure that does not include deferral account treatment (Alternative Approach).

EEC would have preferred to hold a third RFP to acquire the incremental product required to manage the volume and price risk of the RRT load that would otherwise have been managed through the proposed deferral account. EEC considered that there was insufficient time to hold a third RFP process to purchase this product and still permit the Board to approve a final fixed charge by November 30, 2003 as required under the *RDS Amendment Regulation*. EEC estimated that it would require approximately one month to define and execute the RFP for the non-standard product that would be required.

In order to comply with the legislated timeline, EEC proposed to purchase a product from an affiliate, EEMI. This product would eliminate the exposure of RCC and NRCC to any volume or price risk associated with the electric energy required to provide the RRT. EEMI has quoted a price of $19.4 million or $0.00639/kWh for this product.

EEC proposed to add this price as an "Adder" to the applicable Energy Charge of $0.05905/kWh for RCC and $0.05719/kWh for NRCC. EEC noted that this would result in a total Energy Charge, including the Adder, of $0.06544/kWh for Residential Customers and $0.06358/kWh for Commercial Customers.

EEC submitted that the proposed Energy Charges for Residential and Commercial Customers that include the Adder are within the range of the lowest priced bids for the Peak products in the recent RFP's. The lowest price for a Peak product for the Residential RFP was $66.00/MWh and the lowest price for the Commercial RFP was $62.44/MWh. The equivalent price with the Adder is $65.44/MWh for Residential Customers and $63.58/MWh for Commercial Customers. EEC noted that the products purchased through the two RFPs were for standard blocks with price risk but no associated volume risk, load following risk, or market entry and exit risk. EEC considered the fact that the proposed Energy Charge and Adder for both Residential and Commercial Customers is within the range of market based bids received under the RFPs for less risky products provided the Board with the necessary assurance that the product proposed to be purchased from EEMI had been priced at fair market value.

Alternatively, if the Board determined that the statutory timeline set out in subsection 3(4) of the *RDS Regulation* would be met if EEC held an RFP during December to acquire a product approved by the Board prior to November 30, 2003, EEC was prepared to hold a third RFP to acquire the required incremental product.

EEMI informed EEC that EEMI would only hold an open position with respect to the incremental product until the close of business on November 30, 2003. Consequently, the price quoted by EEMI for the incremental product would only be available until that time. In the circumstances, given the nature of the market and the product sought for EEC's 2004 RRT application, if the Board did not approve the purchase of the EEMI product, it would not be appropriate to use the price quoted by EEMI as a proxy or as an indicator. Specifically, if the Board directed EEC to hold an RFP to acquire an incremental product, EEC could not speculate as to what the market price for that product might be at any particular time in the future.

4.2 Views of the Interveners

In PICA's submission, EEC's proposal was "outrageous" and should not be considered by the Board on any basis. Further, the suggestion of using an affiliate transaction as the basis for the final volumes was also inappropriate, particularly as there are no reasonable safeguards or review in place or reasonably expected in the immediate future. Finally, the alternative of a third RFP, even later in the year, could only result in significant prejudice to customers who would be asked to bear the costs of a poorly timed process. Moreover, until volume forecasts are adequately tested and approved, the purchase of such a portfolio may result in over-hedging and unnecessary costs. Therefore, PICA submitted that the Board should reject EEC's alternative proposal in its entirety.

4.3 Views of the Board

While the Board agrees with EEC that the Alternative Approach with an Adder would comply with the *RDS Regulation*, the Board does not agree that the amount of the Adder would necessarily be a reasonable increase to the energy charges. Certainly PICA considered that the overall cost of the energy procured with the Adder was too high.

The Board considers that a fixed charge for energy supplied to RCC and a fixed charge for energy supplied to NRCC is the only portion of EEC's 2004 RRT transition rates that should be approved for the first quarter of 2004 prior to the final tariff proceeding.

Accordingly, in the circumstances, given the short timeframes, the Board will not approve the proposed Adder even on an interim basis. The Board will provide its approach to deal with this issue later in this Decision.

5 SEPARATION OF ENERGY POOLS FOR RCC AND NRCC

Under EEC's proposal, the fixed energy charge for Residential Customers is based on the result of the first RFP and for NRCC is based on the result of the most recent RFP.

5.1 Views of the Applicant

EEC indicated that the approach adopted by EEC takes into account that the energy for NRCC and RCC was procured separately, for reasons beyond the control of EEC in the circumstances, EEC submitted that separate pools were appropriate and noted that the CCA endorsed the use of separate pools in order to minimize the possibility of cross-subsidization between RCC and NRCC.

5.2 Views of the Interveners

CCA

CCA believed that differences in price arising from having two procurement pools and two energy prices would prevent any material cross-subsidization to one group from any other group of customers. CCA submitted that prevention of cross subsidization is important enough to warrant the maintenance of two separate pools.

The CCA was open to use of a single pool if the price differences between the pools was immaterial. The CCA submitted that a change of more than $0.0025 or more than ¼ of a cent per kWh would clearly having material consequences to end-use customer bills.

The CCA was mindful that the "use of a uniform energy charge/kWh for RCC and NRCC may eliminate unnecessary confusion and controversy differing prices may create", but submitted that a materiality test was easily employed and should not create undue confusion.

PICA

Consistent with its position in relation to EESI and EESAI, PICA submitted that the efficiencies of a single pool should offset any differences in prices and/or gain or loss from having two procurement pools and two energy prices.

PICA also submitted that the procurement over an extended period is also in the best interests of customers. Even though the two RFPs were conducted in a short period of time, pooling should provide a better price indicator than a single RFP. The resulting rate should only be used for the first quarter of 2004. The use of a uniform energy charge/kWh for RCC and NRCC may eliminate unnecessary confusion and controversy differing prices may create.

CCG

The CCG submitted that there should be two pools in order to ensure that there would be no cross-subsidization between RCC and NRCC. The CCG submitted that there was no evidence that a single pool would provide significant efficiencies over the use of two pools. Further, a small difference in price between the two pools could be substantial when multiplied by the amount of energy involved. The CCG submitted there was no evidence of the potential confusion and controversy raised by PICA. The CCG saw differing energy charges no differently than other charges that differ from one rate group to another.

5.3 Views of the Board

PICA's proposal to combine the pools for energy procured to achieve cost efficiencies and eliminate the controversy that differing prices may create may be tested in the final proceeding. However, the Board notes that EEC's use of different load settlement profiles for residential and commercial classes would likely lead to different prices for energy for each class in any event.

In the unusual circumstances brought about by the *RDS Amendment Regulation* and in light of the conclusions reached by the Board that the RCC and NRCC transition rates should only be approved for the first quarter of 2004, the Board considers that there would appear to be the need to maintain two distinct pools and sets of deferral accounts for the first quarter of 2004.

Later in this Decision the Board has directed EEC to discuss the RCC and NRCC energy plans with customers. The Board considers that the matter of whether the distinct pools are required on a final basis should be one of the matters discussed.

6 RETURN MARGIN APPLICABLE TO RCC AND NRCC ENERGY RATES

In the Original Application, EEC requested approval of a $13.7 million margin on the energy and non-energy charges made up of two components:

- $8.4 million, the expected value of the risks and expense volatility required to undertake the RRT obligations, and
- $5.3 million, the recovery of those competitive market costs that would normally be recovered by a competitive retail market participant as part of the margin necessary to permit market entry.

EEC indicated that it had allocated the margin between the energy charge and the administration charge on a percentage of revenue basis, since some of the risk relates to non-energy costs.

EEC indicated that the margin did not form part of the base energy charge that constituted the fixed charge for energy for which EEC was seeking final by November 30, 2003 per section 3(4) of the *RDS Regulation.*

In its Revised Application, EEC indicated that the margin requested had increased from $13.7 million to $14.4 million to reflect the impact of the *RDS Amendment Regulation:*

- $8.49 million, the expected value of the risks and expense volatility required to undertake the RRT obligations, and
- $5.87 million, the recovery of those competitive market costs that would normally be recovered by a competitive retail market participant as part of the margin necessary to permit market entry.

Table 4.2 of the Revised Application outlined the revised 2004 Margin Requirement and identified the consequential changes. EEC indicated that the increase was primarily driven by increased implicit costs, that is the Market Entry Recovery Costs and the Lost Opportunity Costs and increased Counter Party Risk caused by the procurement of energy through the NRCC RFP process.

6.1 Views of the Applicant

EEC submitted that inclusion in the *RDS Regulation* of the requirement that obliges the Board to permit a reasonable return should be interpreted as an indication that the provincial government is aware that the RRT is critical to the success or failure of the Alberta competitive retail market for small consumption customers. Among the goals of the 2003 EUA is the development of an efficient market where electricity based on fair and open competition.

EEC submitted that the RRT was a regulated product in a competitive market and competitors that would provide retail electricity products in Alberta must compete with the RRT. EEC submitted that the Board should take the view that the RRT should not hinder the development of an efficient market for electricity based on fair and open competition and should price the RRT as if it were a rate subject to competitive pressures and considerations.

EEC pointed to the evidence of its expert witness that the proposed margin reflects, as closely as possible, the type of recovery that occurs in competitive markets and that one of the reasons that competitive retailers have not been able to penetrate the Alberta retail electricity market to a greater degree is because the regulated rates were significantly lower than competitive rates, making it uneconomic for competitive retailers to compete.

In EEC's view while the RRT is a regulated rate, the outcome of the regulatory process has significant potential to impact the developing competitive market. These competitive market costs reflect the economic opportunity costs associated with both market entry and the provision of a regulated service and are a critical component of the margin if the RRT price is to send the appropriate price signals to competitive entrants.

In response to Calgary's submission that benchmarking or the 2003 approach to the margin was appropriate, EEC indicated that there were structural differences between the 2003 and 2004 RRT. EEC submitted that the EURC believed the recovery of 2003 non-energy costs was guaranteed, whereas they are not guaranteed in 2004. Also EURC reduced the margin applied for in 2003, as ENMAX had not quantified the risks, whereas there is a significant body of evidence quantifying the risks in Appendix E of the 2004 RRT Application and parties have had the opportunity to ask IRs and cross-examine on that evidence. Further, the 2003 margin did not include a competitive market cost component as the 2004 margin does, in order to ensure that the RRT sends the appropriate signals to market entrants.

Interveners had an opportunity to contest EEC's interpretations of section 5(a) of the *RDS Regulation* and did not present an alternative interpretation. EEC submitted that it was not enough for interveners merely to indicate that the margin was large and would be tested in the final proceeding when EEC's evidence was on the record. No alternative interpretations were presented to refute EEC's interpretation and evidence that the margin should be provided on an interim basis.

EEC was also concerned that a suggestion was made in Argument that EEC somehow had an incentive to bump up the RRT rate such that it would make its other offerings competitive. EEC considered it inappropriate that the proposition was not put forth in evidence or to its witnesses in cross so that they could deal with it. EEC submitted that the suggestion should be disregarded on that basis.

In response to Calgary, EEC referred to an IR response indicating that there were instances where regulatory pricing had stalled competitive development.

In response to PICA, EEC submitted that the margin applied for is justified and reasonable when compared to the margin that a competitive firm would require in order to provide a comparable service in the market. Furthermore, EEC refuted PICA's suggestion that EEC had effectively applied for a margin of 13.2%.

6.2 Views of the Interveners

Calgary

Calgary noted that the Board has used different approaches to and tests of interim rates in different proceedings as indicated by the Board in Decision 2002-110. Calgary noted the test in Decision E92036, where the Board indicated that particularly contentious matters of an interim application allow for a reduction in applied for amounts to mitigate what would otherwise potentially result in an over-collection. Calgary submitted that in Decision 2002-108, the Board set out a second approach, in light of the Board's generally accepted practice of approving carrying costs, that customers and the utility can be kept whole by maintaining interim rates at existing levels except in cases where large rate adjustments are required to prevent financial hardship.

Calgary submitted that EEC had failed under both tests to justify the applied for interim RRT rates and, in particular, the return margin. EEC's interpretation of section 5(a) of the *RDS Regulation* and return margin were a highly contestable and contentious component of the interim rate. Further, the margin is based partly on an untested interpretation of the policy and intent behind the *RDS Regulation,* namely, that to encourage competition, the RRT should include a competitive margin since during the transition from regulation, the regulated rate serves as a proxy for the competitive market price.

Calgary submitted that the return margin was based on untested suppositions and evidence. Calgary submitted that the "evidence" on margin was not *prima facie* evidence insofar as it related to matters that are the subject of statutory interpretation and policy. No evidence was provided to support the interpretation or any concrete evidence demonstrating the success of implementing a margin based on the principles presented in evidence in responses to CAL-EPC(RRT)-27(b) and CAL-EPC(RRT)-27(b). Calgary submitted that, in the final proceeding, it would also take exception to all of the other components used build up the margin revenue requirement.

Calgary also noted EEC's admission that it would not suffer any financial hardship if the Board were to approve an interim margin similar to that which EEC would receive in 2003.

Calgary took the position that the margin should be eliminated for commercial RRT rates and reduced to a 2% markup of base energy charges for residential rates. Calgary submitted that the hourly Pool price formula to be used to calculate energy charges for commercial customers should be revised so that the margin component in that formula equaled zero.

In 2003, EEC recovered a 2% markup solely on the base energy charge, which was determined as the sum of a 7 by 24 market price plus a 6 by 16 on-peak adjustment price plus pool trading charges. According to Calgary, the on-peak adjustment was the means by which EEC spread the cost of the on-peak block evenly over all base load hours. In 2004, EEC is proposing to recover its margin of $13.7 million through application of a margin of 6.92% on both the energy and non-energy charges of residential and commercial RRT customers.

Calgary noted that the approved 2003 markup amounted to $0.00093 per kWh.[16] The applied for 2004 margin was three times that on the energy charge alone and EEC applied for another $2.5 million of margin through the administration charge.[17] Calgary was not convinced that the applied for margin was justified or would provide a proper market signal to EEC's RRT customers.

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[16] CAL-EPC(RRT)33(b)

[17] CAL-EPC(RRT)31(e)

Calgary submitted that, on an interim basis, the current markup of 2.0% on the base energy price should be collected through a per kWh charge of $0.001071 for residential customers. No margin should apply for commercial RRT customers as their energy charge was based on flow-through pricing. Further, no margin should be collected through residential or commercial administration charges. The total energy price for residential customers would then be 5.621 cents per kWh an increase of 2.5 % over the current RRT energy charge of 5.482 cents per kWh.

Calgary also submitted that since the only choices available to Calgary residential customers are the EEC RRT or the EEC competitive offer, an artificially high RRT would make EEC's competitive offerings more attractive, therefore encouraging RRT customers to move to one of EEC's fixed price plans. Lower final RRT rates would provide price signals too late for those customers who switched and were bound to the term of EEC fixed price plans. Calgary submitted that the price signals on which customers base their decisions should be the final rates.

Calgary agreed with the idea of encouraging the retail market. However, Calgary submitted that there were still two years left under the *RDS Regulation* to provide for a transition to a full flow-through for residential customers and the timing of the final Decision would be well within that transition period.

Calgary noted that the total applied-for margin revenue requirement of 13.7 million is more than double the margin applied for in the 2003 EURC tariff application for RRO service and over six times the 2003 margin revenue requirement approved by the EURC.

Calgary also noted that the margin was a contentious issue in the 2003 RRO proceeding, as is evident in the decision, and expected it would again be in the final tariff portion of the 2004 RRT proceeding. Calgary submitted that customers should have an opportunity to test the reasoning behind such a significant increase in profit before having to pay the increase.

Further, customers should also have the opportunity to test the method of allocating or classifying the margin revenue requirement for a collection between the energy charge, the administration charge, and as between commercial and residential RRT customers.

CCA

The CCA supported the position of Calgary on the interim return margin and interim rates. The CCA also supported all of PICA's views on these issues.

PICA

PICA noted that, in the Original Application, EEC was requesting a 6.94% margin or a 7.45% markup on its total energy and non-energy revenue forecasts (CAL-EPC-3(h)) on the basis that it was assuming significant forecast risk. PICA submitted that the margin was excessive compared to other independent yardsticks. Further, the recovery of any margin on the energy piece of flow-through rates was inappropriate. PICA noted that it would be addressing the differences that it perceived between provision of RRT to residential and commercial customers in the final proceeding.

In 2003, EURC allowed a markup of 2% on the base energy price plus on-peak adjustments and pool trading charges. PICA allowed that EEC was assured of a greater portion of cost recovery under the EURC margin assumptions, but noted that the risk compensation was for a partially hedged RRT rate.

In 2003, EESAI assumed all forecast risk and was compensated by way of a 3.75% margin. PICA submitted that EEC assumed less risk under EEC's 2004 RRT since EEC has a provision for true-up of residential energy costs, a flow-through rate for commercial energy and true-up of certain non-energy charges such as fee revenue. PICA submitted that, as a result, EEC's interim return markup should be less than 3.75%.

PICA was also concerned about recovery of the return markup on a consumption basis, since PICA considered that there was little direct relationship between return compensation and consumption particularly for commercial customers with flow-through rates. PICA submitted that if the Board allowed an interim return markup, it should be recovered through the fixed administrative charge.

PICA noted that in the Revised Application, EEC was seeking a return margin of 6.88% to apply to both Energy and Non-Energy Costs. In PICA's view no return should be allowed even on an interim, refundable basis since:

- None of these risks or costs has been tested and most, if not all, are highly questionable and require further evidence to support their validity.
- Some risks appear to be duplicative or offsetting, such as customer number volatility and exit risk. In the absence of any substantive evidence, testing or regulatory precedent, the listed risks, costs and requested compensation should not be included on an interim basis. Rather, it should be addressed as part of the final proceeding.
- Unlike EESAI and EESI, EEC was not assuming any volume or price risks in relation to the hedged portfolio since it proposed use of deferral accounts with true up variances in price and volumes, leaves all the risk with the customers.

Even if the risks and costs suggested by EEC were later found to be reasonable, in whole or in part, PICA considered the level of return requested by EEC to be completely out of line with other independent yardsticks:

- EEC's previous regulator allowed a mark up of 2% on the 2003 base energy price plus on peak adjustments plus pool trading charges. Although under the EURC's margin assumptions EEC was assured a greater portion of cost recovery, it is still instructive to note the risk compensation allowed by the EURC for a partially hedged RRT rate in 2003.
- In Decision 2002-112, the Board approved the 2003 RRT energy and non-energy settlement for EESAI wherein EESAI assumed all forecast risk related to energy and non-energy components and was compensated by way of a 3.75% return on each. By contrast, EEC's application indicates key risk differences, including a true up of energy costs and certain elements of the non energy charge, such as fee revenue, through deferral accounts.

In the absence of tested evidence to the contrary, PICA submitted that EEC should, at most, only be allowed a return of 3.25% on non-energy charges.

PICA noted the calculation of the total energy charge in Table 3.5 of the Revised Application included a margin equal to 13.2%, rather than 6.88% (0.05173/.00392). PICA submitted that, corrected, the proposed total energy charge should be no greater than $0.05684/kWh. PICA indicated that it had additional issues concerning the total energy charge calculation that could not be adequately addressed until the time of the final proceeding, such as the validity of charging a margin on the hedge procurement charge.

Given the magnitude of the potential impact on customers of EEC's return margin on the energy charges, PICA submitted that it should not be approved, even on an interim basis.

CCG

CCG supported the position of Calgary on the interim return margin. CCG did not see any justification for a return margin on any part of the regulated rate. CCG agreed with PICA that if any return is allowed by the Board it should be a fixed amount on the administration charge and not a percentage of pool price.

6.3 Views of the Board

Section 5(1)(a) of the *RDS Regulation* (as amended by the *RDS Amendment Regulation*) indicates that:

> **5(1)** When considering an application for approval of a regulated rate tariff under section 103 of the Act, the Board must
>
> (a) have regard for the principle that a regulated rate tariff must provide the owner with a reasonable opportunity to recover the prudent costs and expenses incurred by the owner and a reasonable return … .

The Board is not satisfied at this time that the margin component of $5.87 million to permit market entry can properly be considered as either part of the prudent costs and expenses incurred by the owner or part of a reasonable return. In the circumstances, the Board does not consider it appropriate to approve this amount on an interim basis, particularly in light of the serious questions raised by parties. Therefore, the Board considers that this component of EEC's requested margin should be considered during the final tariff portion of this proceeding.

The Board notes EEC's position that the remainder of the margin of $8.49 million, or 60% of the requested total margin of $14.4 million, relates to the expected value of the risks and expense volatility required to undertake the RRT obligations. While the Board is not necessarily convinced that the risks inherent in EEC's and EESI's provision of their respective RRTs in their respective service territories will be equal, the Board notes that EESI charges margins of 2.49%[18] on energy and 2.18%[19] on transmission and distribution charges.

According to Exhibit 3-204, EESI has calculated that the total (i.e. energy, transmission and distribution) return margin would be 3.80% if expressed on energy alone. The Board notes that

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[18] This figure is equal to the after tax margin agreed to in the EESAI RRC Negotiated Settlement.

[19] This figure is equal to the after tax margin agreed to in the EESAI RRC Negotiated Settlement.

EESI has also requested a return on equity in respect of assets provided in the provision of non-energy services.

On the surface, it appears to the Board that EESI faces higher procurement risks than EEC in provision of the RRT service without the energy deferral accounts EEC proposes. Given that the margin components proposed by EEC are untested, this factor suggests to the Board that EEC should be granted a lower total return margin than EESI on an interim basis.

Interveners supported Calgary's position that the existing margin of 2% allowed by the EURC should be applied on an interim basis.

On balance, the Board considers that an interim return margin of 2% is not unreasonable having regard to the following:

- It is equal to the previous return margin allowed by the EURC; and
- EEC's risks appear to be lower than EESI's considering the proposed EEC energy deferral account which transfers all hourly price and volume risks to customers.

Accordingly, the Board approves a return margin on an interim basis of 2% for both energy and non-energy components of EEC's interim tariff. The Board will determine the final level of the margin in the final tariff proceeding.

7 RCC AND NRCC PLAN COMPLIANCE WITH *RDS REGULATION*

7.1 Background

Subsequent to the enactment of the *RDS Amendment Regulation,* EEC filed a letter dated November 14, 2003 indicating that EEC would amend its 2004 RRT application to provide a transition rate for eligible customers other than RCC. EEC did not consider that a change was required to the residential transition rate applied for in its Original Application.

EEC indicated that it intended to file the amendments to its 2004 RRT application on or before November 21, 2003. EEC recognized that the timing of the *RDS Amendment Regulation* and the fact that the date by which a final fixed charge for electric energy must be approved had not been extended placed the Board and all stakeholders in a difficult position, with little time to react and to assess the proposed changes to the Application.

In light of the deadlines facing EEC and the Board, EEC requested that any comments by interested parties in relation to EEC's intended approach be submitted by the close of business November 17, 2003. EEC further indicated that, if the Board disagreed with EEC's view that the applied for transition rate for residential customers complied with the *RDS Amendment Regulation*, EEC would attempt to procure products to cover the unhedged portion of the residential load. In that event, EEC anticipated that the overall price would be significantly higher.

No party provided any comments in response to EEC's November 14, 2003 letter.

At the request of the Board, EEC submitted a further letter on November 18, 2003, setting out the reasons supporting its view that its proposed approach to energy procurement complied with section 5(2) of the *RDS Regulation*, which had been added by the *RDS Amendment Regulation* on November 4, 2003.

In a letter dated November 18, 2003, the Board indicated that:

> …based on the information currently before it that a deferral account that transfers "procurement risk of acquisition" to customers may not comply with section 5(2) of the RDS Amendment. The Board considers that "procurement risk of acquisition" includes the pool price risk on acquisition of energy from the power pool must remain with EPC and should not be subject to the deferral account treatment that EPC proposes.

EEC filed the Revised Application on November 21, 2003. EEC continued to assert that its proposal to use deferral accounts to manage volume and price risk for its RCC transition rate complied with section 5(2) of the *RDS Regulation*. As a result, EEC applied for approval of a NRCC transition rate with a fixed energy charge and fixed energy charge and deferral accounts similar to the RCC transition rate. EEC indicated that it had secured hedges for about 92% of the energy required by NRCC and the remainder of the load was unhedged.

In the alternative, EEC proposed alternative transition rates without deferral accounts should the Board continue to hold the view set out in its November 18, 2003 letter that the deferral accounts applied for by EEC would not comply with section 5(2) of the *RDS Regulation*. In that case, EEC requested that the Board approve the alternative transition rates based on the same fixed energy charges without deferral accounts, but with an Adder of $0.00639/kWh. The Adder was the price[20] for a product that would eliminate the exposure of eligible RRT customers to any volume or price risk associated with the electric energy required to provide the RRT.

EEC took the position that the deferral accounts were an integral part of EEC's proposed transition rates and that it would not be appropriate for the Board to approve the proposed transition rate that includes the associated deferral accounts and simply strip them away without approving the alternatively proposed Adder.

7.2 Views of the Applicant

In its November 18, 2003 letter, EEC submitted that its RCC energy procurement plan and price setting arrangement complied with the amended *RDS Regulation* for the following reasons:

- The reference to "procurement risk of acquisition" in section 5(2) of the *RDS Regulation* refers to the credit and counter party risks, which remains with EEC.
- Section 5(2) cannot be interpreted in isolation but must be consistent with the entire *RDS Regulation* as amended. It is not reasonable or consistent with the intent of the whole, amended *RDS Regulation* to force an owner to assume, rather than manage, a significant portion of the financial risk associated with RRT supply obligations.
- Section 5(2) cannot mean forecast risk or price risk. For example, if section 5(2) were interpreted in a manner that required owners to hedge 100% of the RRT load, with no ability to adjust the rates for long or short positions under the hedges, this would not only

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[20] The price for the product was quoted from ENMAX Energy Marketing Inc. (EEMI)

> be contrary to the clearly stated purpose of the subsection, but would very significantly increase the magnitude of risk that owners or RRT providers were forced to assume, which should also result in a correspondingly large increase in the return or margin that an owner or RRT provider must be permitted to earn under paragraph 5(1)(a) of the *Regulation*.

EEC noted that for Residential Customers, EEC has 86% of the total forecast load hedged and 14% unhedged, and for Commercial Customers 92% is hedged and 8% is unhedged. As shown in BR-EEC (RRT)-8, assuming no variance in the forecast, if the Pool price increases by 30%, the price of energy to Residential Customer would increase by less than 2%. EEC submitted that, together, the hedges and deferral accounts would minimize the pricing fluctuations to the customer.

Residential Customers have a total of 20% exposure to the Pool price and Commercial Customers have a total of 15% exposure. The value of the exposure is offset by the revenue received by selling excess energy into the market, when EEC is long on energy, and the revenue received through the fixed price energy charge when EEC is short on energy. This mechanism would offset the customer's pricing risk and minimize the need for adjustments to the energy charge.

EEC submitted that the deferral account also would allow EEC to manage volume and customer attrition risk as permitted by section 2(2) of the *RDS Regulation*. If more customers leave the system than forecast, the amount of short volume decreases and the amount of the total load hedged increases. Conversely, if more customers remain on the RRT than forecast, then EEC can purchase energy at the market to provide service and the total amount hedged decreases.

EEC noted that, while the fixed price for energy does not change throughout the year, the total price for energy would change quarterly due to the disposition of the deferral account through the rate rider. The net balance, rather than the Pool price, would flow through the rate rider to customers. The Losses deferral account would also flow through the rate rider to customers.

In response to PICA's submission that EEC's Alternative Approach is "outrageous" and the proposed transaction with an affiliate is inappropriate, EEC noted that the Alternative Approach is suggested only in alternative to EEC's preferred approach of procuring energy through a market-based RFP process. In the unusual circumstances, with a November 30, 2003 deadline, EEC saw no option but to obtain a price quote from EEMI. If EEC's interpretation of section 5(2) was not accepted, it would be forced to assume very significant volume and price risks in providing the RRT. EEC is entitled, under section 2(2) to make arrangements to manage these risks, and in these circumstances, EEC submitted that its Alternative Approach was reasonable.

EEC noted CCG's agreement with EEC that section 5(2) of the *RDS Regulation* does not preclude the use of deferral accounts, particularly where the unhedged portion of the energy supply is small.

In response to PICA's suggestion that EEC should procure its energy quarterly, rather than procuring the energy in a single tranche, EEC submitted that it was not clear that procuring energy through several processes during 2004 complied with the requirements of the legislation. EEC submitted that PICA had notice of the manner in which and the means by which EEC proposed to procure energy for NRCC and expressed no concerns with that manner or process, either in the interim hearing, or before the RFP was held. EEC has now purchased energy for 2004, through a market-based RFP, to provide service to NRCC under a transition rate.

7.3 Views of the Interveners

CCA

The CCA supported all of PICA's views on these issues.

PICA

PICA was concerned about the potential impact of the entrance of parties seeking large volumes of energy for the next year over a short period of time, particularly this late in the year. PICA submitted that it was essential that the distribution utilities not undertake hasty and imprudent acquisition processes or portfolio designs. PICA advocated use of ongoing procurement practices with a diverse portfolio of energy products, including annual, quarterly, monthly, base, peak and super peak products. Customers cannot afford the impact of a scramble to produce a hedged RRT for RCC and NRCC and the higher prices implied.

In addition to the considerable disadvantage customers face in terms of the hedged rate, NRCC are also greatly prejudiced in their ability to test the contents of the proposed NRCC RRT applications. In EEC's case, the application was filed on Friday, November 21, 2003, and submissions were required by Tuesday, November 25, 2003. PICA considered there was no time for any effective or reasonable review of the Application through an IR process, either formal or informal, nor through review with experts engaged on behalf of customers.

In PICA's submission, any decision rendered by the Board on November 30, 2003, must take into account the fact the Application had not been tested. Consequently, PICA submitted that any applications for new or unprecedented costs should be viewed as unsubstantiated and unsupported, disallowed on an interim basis and left for full consideration as part of the final proceeding scheduled for March 2004. In PICA's view, this approach was the only way to provide customers with any meaningful opportunity to evaluate and address their concerns and to mitigate the impacts of the exceedingly poor timing of the *RDS Amendment Regulation*.

As indicated previously, PICA submitted that, while RRT providers are placed under similar timing pressures, it is the customers who would ultimately bear the majority of the costs related to the development of hedging mechanisms at this late date. The potential magnitude of these costs is perhaps most obvious in the case of EEC's proposed NRCC RRT.

CCG

CCG questioned whether the *RDS Regulation* allows a portion of the energy price risk to be borne by the customers. The CCG saw merit in the interpretation put forward by EEC and took the position that the *Regulation* does not preclude the use of a deferral account for the unhedged portion of an energy portfolio, particularly when the unhedged portion is small. CCG submitted that it is in the interest of customers to bear a small part of the energy price risk in order to avoid the payment of a risk premium.

The CCG saw EEC's 8% unhedged energy as being similar to the energy that is potentially unhedged under the energy price setting plan proposed by EESI. If the Board approved the plan proposed by EESI, including the potential for unhedged energy to be procured with the customers bearing the price risk, the Board should likewise allow EEC's transition rate to have an unhedged portion for which customers bear the price risk.

AE

AE was opposed to the approval of the return margin for the RRT on other than an interim refundable basis. AE submitted that, with the release of the *RDS Amendment Regulation* the Government of Alberta had significantly changed the legislative framework under which the RRT is to be provided. Specifically, section 5(2) of the *Regulation* now requires the Board to approve the financial arrangements proposed by the RRT provider to ensure that the procurement risk of acquisition remains with the RRT provider. AE submitted that this change significantly increases the risk to the RRT provider, and under such changed circumstances, the Board has no alternative but to conduct a review of the requested return margin to ensure that the resulting tariff was just and reasonable, and in the public interest.

7.4 Views of the Board

The Board has given careful consideration to EEC's view that the EEC energy procurement plan and price setting arrangement are in compliance with the *RDS Regulation* as amended by the *RDS Amendment Regulation.* The Board particularly notes that EEC anticipated that the overall energy price to customers would be significantly higher if EEC were to attempt to procure products to cover the unhedged portion of the RRT load.

The Board also notes that the CCG saw merit in the interpretation put forward by EEC, and took the position that the amended *RDS Regulation* does not preclude the use of a deferral account for the unhedged portion of an energy portfolio, particularly when the unhedged portion is small. CCG submitted that it was in the interest of customers to bear a small part of the energy price risk in order to avoid the payment of a risk premium.

Notwithstanding these views, the Board considers that the *RDS Regulation* as amended by the *RDS Amendment Regulation* precludes the Board from approving the EEC energy procurement plan and price setting arrangement in the form proposed in the Revised Application. The Board continues to be of the view expressed in its November 18, 2003 letter that:

> …based on the information currently before it, that a deferral account that transfers "procurement risk of acquisition" to customers may not comply with section 5(2) of the RDS Amendment. The Board considers that "procurement risk of acquisition" includes the pool price risk on acquisition of energy from the power pool must remain with EPC and should not be subject to the deferral account treatment that EPC proposes.

The Board notes that EEC has proposed an approach where customers bear the hourly price and volume risk on the exposed portion of the customer load. Therefore, the Board is not persuaded that EEC's energy procurement and transition rate approach (which leaves all hourly price and volume risk with customers via a deferral account) complies with the legislative framework set out in the amended *RDS Regulation*. For that reason, the Board is not satisfied, at this stage, that EEC's Plan will result in a "transition rate" as defined by the amended *RDS Regulation*.

In these circumstances, the Board considers that EEC should meet with EEC's customers and other stakeholders along with an independent energy advisor to discuss possible changes to the EEC energy procurement plan and price setting arrangement. The purpose of the meeting(s) would be to attempt to arrive at a consensus respecting the approach that EEC should follow respecting the price and volume risks related to EEC's provision of RCC and NRCC transition rates to comply with the amended *RDS Regulation.*

The Board recognizes that this direction to EEC and customers differs somewhat from the views expressed by the Board in Decision 2003-096. However, following careful consideration of the particular views expressed in relation to EEC's Revised Application in light of the amended *RDS Regulation*, the Board considers that the serious issues raised by the Application warrant discussion among the parties.

The Board considers that parties should be given an appropriate length of time to deal with this significant issue. Accordingly, pursuant to the powers granted to it under the *RDS Amendment Regulation No. 2,* the Board will extend the date by which it must approve a transition rate for EEC that complies with the *RDS Regulation*, to April 1, 2004.[21] This extension affords a period of grace from January 1, 2004 to March 31, 2004 before the full force of the *RDS Amendment Regulation* comes to bear on the RCC and NRCC energy portions of EEC's RRT.

The Board recognizes that an RRT is required for EEC to be effective January 1, 2004 (since its currently approved RRT will expire at the end of 2003). In the circumstances, while the Board has extended a grace period for discussion, during which the full force of the *RDS Amendment Regulation* will not apply to EEC, the Board considers it reasonable to give effect to the overriding intent of the *RDS Amendment Regulation* in approving RCC and NRCC RRTs for the first quarter of 2004. That intent was to offer "transition rates" to both RCC and NRCC from January 1, 2004, rather than exposing NRCC to "flow-through rates" which were to be calculated according to section 4(2) of the *RDS Regulation*. For the reasons mentioned above, however, the Board will not adhere strictly to the provisions of the *RDS Amendment Regulation,* specifically section 5(2), until April 1, 2004, as they may apply to EEC.

The Board notes that there are a number of options that parties can consider in stakeholder discussions each of which would be effective April 1, 2004 on a going forward basis if approved by the Board, including, but not limited to, the following:

- Carry out a third RFP to obtain product to reduce the currently unhedged load.
- Implement a "buy as you go" approach to hedging the currently unhedged RCC and NRCC load using quarterly and monthly products similar to the EESI and EESAI Plans.
- Transfer the price and volume risk of the unhedged load to EEC in return for an adder or return margin to be dealt with in the final proceeding.
- Retain the existing EEC Energy Plan and request that the Government of Alberta further amend the *RDS Regulation* to clearly permit an energy procurement plan that includes a financial arrangement whereby customers are allowed to bear all of the price and volume risk on the provision of the transition rate, including by way of appropriate deferral accounts.

In suggesting these options for discussion, the Board should not be taken to have expressed any view as to which, if any, would be just and reasonable and in the best interests of EEC and its customers. Each of the options has advantages and disadvantages and the risks of each should be thoroughly explained to EEC and its customers by the independent energy advisor. The Board will provide a staff member in the role of observer if requested by parties.

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[21] The *RDS Amendment Regulation No. 2* authorizes the Board to extend this date to no later than July 1, 2004.

Accordingly, the Board directs EEC to file a report, on or before March 1, 2004, setting out the results of the discussions and any consensus reached. The Board considers this matter to be both urgent and significant and would be amenable to any consensus being formalized by way of a negotiated settlement respecting a revised EEC Energy procurement plan, notwithstanding the views expressed by the Board in Decision 2003-096.[22] The Board would consider the report and any consensus option, including any consensus on return margin, prior to April 1, 2004. If no return margin was arrived at respecting any consensus option, the appropriate return margin associated with the consensus option would be deferred to the final proceeding.

In the event of a lack of consensus respecting any option, the Board, after an appropriate process, will approve a plan, effective April 1, 2004, that the Board considers would be just and reasonable and in the best interests of EEC and its customers.

8 RCC AND NRCC NON-ENERGY RATE MATTERS

8.1 Non-Energy Rates

In its Revised Application, EEC proposed the following non-energy rates:

1. A margin of 6.88% to apply to both Energy and Non-Energy Costs.
2. The 2004 Interim and Final Rate Schedules set out in Section 2 of the Revised Application.
3. An Administration Charge for Residential Customers of $0.2903 per customer site per day or $8.85 per customer site per billing month. The change results from the update to the margin and allocation of margin between the Residential and Commercial Customers.
4. An Administration Charge for Commercial Customers of $0.3883 per customer site per day or $11.84 per customer site per billing month. The change results from the update to the Commercial Customer forecast, inclusion of costs resulting from the legislative amendments, margin and the allocation of margin between the Residential and Commercial Customers.

EEC proposed to move from its former 2003 rate structure of a fixed monthly charge combined with a per kWh charge to an Administration Charge billed on a flat daily rate.

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[22] The Board notes that EESAI and EESI concluded a 2004-2005 Energy Plan with their respective customers.

RCC

EEC proposed a fixed monthly Administration Charge to cover billing and the other costs of providing the RRT to RCC. In the Revised Application, EEC indicated that there was no change in the Administration Charge arising from the change in the margin.

Table 5. RCC Non-Energy Charge Calculation

	Residential
Non Energy Revenue Requirement ($000s)	31,007
Customer Forecast (000s)	314
Annual Cost per Customer	98.89
Number of days/year	366
Average Daily Revenue Requirement	$0.2702
Margin	$0.0201
Administration Charge	**$0.2903 per day**

NRCC

In the Revised Application, EEC indicated that, while the non-energy revenue requirement does not change as a result of the *RDS Amendment Regulation*, the Commercial Customer forecast was updated to reflect the likelihood that more customers would be retained on RRT service with the transition rate (82% commercial customer retention) than with a flow-through energy charge (53% commercial customer retention). As a result, EEC's proposed Administration Charge for Commercial Customers decreased from $0.4985/day to $0.3883/day as calculated in the table below:

Table 6. NRCC Non-Energy Charge Calculation

	Small Commercial
Non Energy Revenue Requirement ($000s)	2,373
Customer Forecast (000s)	18
Annual Cost per Customer	132.35
Number of days/year	366
Average Daily Revenue Requirement	$0.3616
Margin	$0.0267
Administration Charge	**$0.3883 per day**

The fixed monthly charge, including margin, decreased from $15.20/month to $11.84/month.

8.1.1 Views of the Applicant

In response to PICA, EEC indicated that the only change to the Administration Charge in its Revised Application is a consequence of the revised forecast. EEC considered that PICA had ample opportunity to test the make-up of the Administration Charge through IRs and in the interim hearing and had provided no evidence to support its suggestion that there is duplication in the Administration Charge. EEC submitted that the calculation of the Charge is transparent and substantiated by the costs set out in the schedules. Furthermore, EEC requested only interim refundable approval of this Charge.

EEC also noted that the existing 2003 Administration Charge was higher than the Charge proposed for 2004.

8.1.2 Views of the Interveners

Calgary

Calgary submitted that the margin component should be excluded for the purpose of the interim Administration Charge. The Charge for residential customers would then be reduced to $0.2702 per customer site per day, or $8.24 per customer site per billing month. The Charge for commercial customers receiving RRT service would be reduced to $0.4639 per customer site per day, or $14.15 per customer site per billing month.

Calgary noted that the 2004 RRT applied-for non-energy cost revenue requirement is $33.4 million. In its 2003 RRO tariff application to the EURC, EEC applied for a non-energy cost revenue requirement of $34 million, as indicated on page 24 of the EURC Decision. Calgary's primary concern with respect to the non-energy charge rate structure was the inclusion of a margin collection component on an interim basis.

CCA

CCA supported the positions of Calgary and PICA.

PICA

PICA noted that EEC was seeking an $11.84 per customer site per billing month administration charge for commercial customers, which includes an untested return margin.

CCG

The CCG did not support the finalization of any non-energy portion of the transition rates proposed by EEC and considered they should be tested more fully in the final proceeding.

8.1.3 Views of the Board

The non-energy charges of the other RRT providers that the Board regulates are fixed charges only. Therefore, the Board accepts that it is appropriate for EEC, in principle, to move from its former 2003 rate structure of a fixed monthly charge combined with a per kWh charge to an Administration Charge billed on a flat daily rate.

The Board agrees that the level of interim non-energy rates should not reflect the EEC requested final return margin. Earlier in this Decision the Board has determined that the interim margin should be 2%. Given EEC's method of calculating the margin on Residential Non-Energy Charges, the Board considers that EEC's Residential Non-Energy Charge in its Revised Application should change from that applied for in the Original Application. Therefore, the Board approves interim non-energy charges, calculated at a return margin of 2%, as set out below:

Table 7. Board Approved RCC and NRCC Non-Energy Charge

	Residential	Small Commercial
Average Daily Revenue Requirement	$0.27020	$0.36160
Margin (2% of above)	$0.00540	$0.00723
Administration Charge	**$0.27560 per day**	**$0.36883 per day**

8.2 Fee Revenue Deferral Account

EEC proposed that a Fee Revenue Deferral Account would be employed to track the variances from actual revenues to forecast revenues for final notice fees, late payment penalties and service fees (Schedule 9). The 2004 forecast of Fee Revenue was provided in Table 5.2[23] and totaled $4,561,000. The balance in the deferral account would be credited or refunded to the customers on an annual basis.

8.2.1 Views of the Applicant

EEC submitted that the Fee Revenue Deferral Account was for those costs that cannot be reasonably forecast or which cannot be reasonably controlled.

8.2.2 Views of the Interveners

Calgary

Calgary did not oppose the approval and establishment of the applied-for deferral accounts in the interim tariff, given that the details of the deferral accounts would be reviewed during the final tariff portion of this proceeding.

8.2.3 Views of the Board

The Board is not prepared to accept, on an interim basis, EEC's evidence that these amounts are particularly difficult to forecast and/or not reasonably controllable. Further, the Board considers that it would be more appropriate to consider the merits of using a Fee Revenue Deferral Account that transfers risk to customers in the context of EEC's overall risk and margin determination. Therefore, the Board is not persuaded that it is appropriate to implement a Fee Revenue Deferral Account on an interim basis.

Accordingly, the Board denies EEC's request to implement a Fee Revenue Deferral Account on an interim basis. The final treatment of these fees and the fee revenue forecast of $4,561,000 may be tested in the final proceeding.

8.3 Hearing Cost Reserve Account

The Hearing Cost Reserve Account would be established to recover Board-approved regulatory hearing costs for the EEC and the approved intervener costs. The 2004 forecast of $2,177,000 is provided in Table 5.3. The balance in the Hearing Cost Reserve Account would be credited or refunded to the customers on an annual basis.

8.3.1 Views of the Board

The Board agrees with EEC that a Hearing Cost Reserve Account should be established effective January 1, 2004. This is consistent with the treatment of hearing costs for other utilities that the Board regulates. However, the Board notes that EEC's forecast of hearing costs was not fully tested during the interim proceedings. The Board considers EEC's forecast of hearing costs of $2,177,000 may be tested during the final proceedings.

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[23] As revised in Exhibit 2-009

9 SUMMARY OF APPROVED RRT INTERIM RATES

In the Revised Application, EEC proposed the following interim RRT rates that reflected EEC's proposed final RRT rates.

Table 8. EEC Proposed 2004 Interim and Final RRT Rates

Rate	Residential Customers	Commercial Customers
Energy Charge	$0.05915/kWh	$0.05719/kWh
Administration Charge	$0.2903 per day	$0.3883 per day
Energy Market Charge/Refund	$0.00/kWh[24]	$0.00/kWh[25]
System Access Service Charge	Per Distribution Tariff	Per Distribution Tariff
Distribution Access Service Charge	Per Distribution Tariff	Per Distribution Tariff
Local Access Fee	Per Agreement with the City of Calgary	Per Agreement with the City of Calgary

9.1 Views of the Board

In this Decision, the Board has determined that the interim RRT rates summarized in the table below and set out in Schedule A of this Decision are appropriate.

Table 9. Board Approved 2004 RRT Interim Rates

Rate	Residential Customers	Commercial Customers
Energy Charge	**$0.05620/kWh**	**$0.** 0.05437/kWh
Administration Charge	**$0.27560 per day**	**$0.368830 per day**
Energy Market Charge/Refund	**$0.xxxx/kWh**	**$0.xxxx/kWh**
System Access Service Charge	Per Distribution Tariff	Per Distribution Tariff
Distribution Access Service Charge	Per Distribution Tariff	Per Distribution Tariff
Local Access Fee	Per Agreement with the City of Calgary	Per Agreement with the City of Calgary

Accordingly, the Board approves the RRT rates set out in Schedule A of this Decision on an interim basis effective January 1, 2004.

EEC also provided forecast illustrative bill comparison templates (Appendix 2 to this Decision) using its proposed RRT rates for typical customers in each customer class in the format requested by the Board in previous EESAI RRO/RRT proceedings. The illustrative bill comparisons included known changes to the EPC DT, the Alberta Electric System Operator's Tariff and associated rate riders. The Board inserted the interim rates in Table 9 above to update the illustrative bill comparisons to reflect the interim rates approved in this Decision.

It should be noted that the apparent increases in the RCC and NRCC administration charges shown on the bill comparisons in Appendix 2 from 2003 to 2004 are a result of the change to the RCC and NRCC non-energy rate design methodology approved by the Board on an interim basis earlier in this Decision. Previously, a portion of the administration cost was recovered by way of a variable cost included in the energy charge.

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[24] To change quarterly based on the Residential energy deferral account and losses deferral account balances.

[25] To change quarterly based on the Commercial energy deferral account and losses deferral account balances.

10 RRT TERMS AND CONDITIONS AND FEE SCHEDULE

10.1 Changes to RRT Terms and Conditions of Service (T&Cs)

EEC provided the changes to its proposed 2004 T&Cs from its existing T&Cs in response to BR-EEC (RRT) 13. In that response EEC indicated that there were no significant changes. Only definitions and terminology have been updated to reflect legislative changes in 2003 and the liability provisions have been amended to harmonize with the relevant provisions of the DT T&Cs.

10.1.1 Views of the Applicant

EEC submitted that the proposed 2004 T&Cs should be approved on an interim basis. EEC noted that only Calgary objected to the approval, on an interim basis, of the T&Cs EEC proposed. EEC submitted that Calgary provided no rational for its submission. EEC submitted that since there were no substantial changes to the T&C's, there was no reason they should not be approved on an interim basis.

10.1.2 Views of the Interveners

Calgary

Calgary submitted that the current T&Cs should be used on an interim basis to allow parties to test the proposed changes during the final tariff portion of this proceeding.

PICA

PICA indicated that it did not object to the T&C's that EEC proposed to implement on an interim basis.

10.1.3 Views of the Board

The Board notes that only Calgary objected to the approval of the interim T&Cs proposed by EEC.

The Board also notes that while EEC's proposed 2004 T&Cs are different from EEC's current T&Cs, most of the differences are due to the legislated changes that brought EEC under the Board's jurisdiction, including the enactment of the *RDS Regulation*.

Therefore, the Board approves the T&Cs proposed by EEC (Attached as Schedule B of this Decision) on an interim basis.

10.2 Fee Schedule

EEC provided the changes in its proposed 2004 Fee Schedule from its existing Fee Schedule in response to BR-EEC (RRT) 13. EEC indicated that the changes reflected a greater detailing of services related to customer re-energization and de-energization and the variety of data services available to customers. Further, the services and fees are harmonized with those in the EPC DT. The level of fees for 2004 reflected updated costs structures and an effort to ensure consistency across similar service offerings.

The Board earlier dealt with the Fee Revenue Deferral Account proposed by EEC in conjunction with the Fee Schedule.

10.2.1 Views of the Applicant

EEC submitted that the proposed 2004 Fee Schedule should be approved on an interim basis. EEC noted that only Calgary objected to the interim approval, but submitted that Calgary provided no rationale for its submission.

10.2.2 Views of the Interveners

Calgary

Calgary submitted that the current fees for additional services should be used on an interim basis to allow parties to test the proposed changes during the final tariff portion of this proceeding.

PICA

PICA noted that there were some RRT fee increases for services and submitted that the any interim fee increases should be refundable if different from those approved on a final basis.

PICA was also concerned some of the components of fee revenue may be correlated to items for which EEC is proposing to assume forecast risk. For example, there could be a correlation between penalty revenues and bad debt expense. EEC was proposing to assume full forecast risk on bad debt expense but not on penalty revenue. PICA submitted that EEC's proposed Fee Revenue Deferral Account should be approved on an interim basis only and the issue of which items should be included in the Deferral Account should be addressed before final approval.

10.2.3 Views of the Board

The Board notes that EEC's existing Fee Schedule does not include fees for many of the services included in EEC's proposed 2004 Fee Schedule. However, the Board considers it appropriate for customers to be charged for the additional services on the basis of EEC's cost to perform the service. Most of the fees in EEC's Fee Schedule are flowed through from EPC's DT Fee Schedule[26] with the exceptions of the Application Fee of $10.00 per request, Dishonored Cheque Fee of $25.00 per cheque and Final Notice Fee of $15.00 per notice. No intervener suggested that these fees proposed by EEC are out of line with the costs for similar services for other utilities regulated by the Board.

For the above reasons, the Board considers that the proposed EEC Fee Schedule is more appropriate for 2004 than the existing EEC Fee Schedule.

Accordingly, the Board approves implementation, on an interim basis, of the Fee Schedule attached as Schedule C to this Decision.

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[26] Approved in Decision 2003-084 dated November 14, 2003

11 EEC RESIDENTIAL RATE CLASSIFICATION

11.1 Introduction

Under the terms of the *RDS Regulation* in force at the time of the interim hearing, only "rate classification customers" as defined in the *Regulation* were entitled to the benefit of a hedged transition rate beyond the end of 2003. All other eligible customers ("non-rate classification customers") were entitled only to receive a flow-through rate as of January 1, 2004.

The Care Center Group (CCG) with members in the City of Calgary[27] intervened in the proceedings respecting EEC's 2004 RRT Application to request that the member centers be defined in EEC's 2004 RRT as "residential rate classification customers". So defined, the CCG members would become eligible to receive a transition rate under EEC's 2004 RRT. In the alternative, the CCG at least hoped that it would be eligible for a flow-through energy rate under EEC's 2004 RRT.

While the Board was deliberating on EESI's 2004 RRT Application, the Government of Alberta announced that it intended to extend the availability of the transition rate to ***all*** eligible customers through to June 30, 2006. On November 5, 2003, the Minister of Energy enacted the *Regulated Default Supply Amendment Regulation* by way of Ministerial Order 73/2003 (*RDS Amendment Regulation*). The effect of the *RDS Amendment Regulation* is to require an RRT provider to offer ***only*** a transition rate to all eligible customers until June 30, 2006, and to offer ***only*** a flow-through rate to all eligible customers after July 1, 2006.

With the exception of the eligibility of St. Michael's Extended Care Center Society (St. Michael's), the *RDS Amendment Regulation* has rendered moot the question of the eligibility of members of the CCG for a transition rate under EEC's 2004 RRT. Under the terms of this new *Regulation*, it is clear that any CCG member with forecast annual consumption of less than 250 MWh is an eligible customer entitled to a transition rate until June 30, 2006, whether that customer is a rate classification customer or non-rate classification customer.

The only remaining question is whether current or possible future members of the CCG may, in the future, be forecast to consume more than 250 MWh/year and be eligible at all for service under EEC's 2004 RRT.

11.2 Views of the Applicant

EEC was not opposed to having discussions with the CCG respecting the issue of including multi-unit residential buildings as residential rate classification customers.

EEC noted that modifying the definition of "residential" in the RRT to accommodate bulk-metered multi-residential units would have two consequences. First, the billing system would have to be changed, at some cost. EEC submitted that this would require a cost benefit analysis that is typically necessary in considering these types of decisions. Secondly, the fixed blocks of energy for the 2004 RRT have already been purchased for the existing and forecast number of residential customers in 2004. EEC submitted that modifying the definition of residential to accommodate the CCG's request would increase the number of residential customers in 2004. EEC noted that there was no evidence on the record regarding the magnitude of that increase.

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[27] Calgary members consisting of Glamorgan Care Center, Mayfair Care Centre, Newport Harbour Care Centre

EEC submitted that any increase in the number of residential customers higher than forecast in 2004 would effectively result in all RRT customers being subjected to the volatility of pool price for more hours in 2004 than presently forecast. EEC submitted that other options were available to deal with the CCG's issue and others in the same situation through, for example, other retailers. If the Board were inclined to direct that the definition of residential be modified to accommodate bulk-metered multi-unit residential units, EEC submitted that it would be appropriate to defer implementation until 2005, in order to minimize the impact on existing residential customers.

EEC also cautioned that cost containment and cost recovery in these circumstances would lead to some customers being harmed. For example, assuming EEC could procure hedged energy in 2004 for CCG members, CCG might not be prepared to bear all of those costs. By the same token, existing customers can be expected to object to bearing any additional costs of serving these new rate classification customers.

EEC noted that the CCG submitted that all of its members, whether or not they have an annual consumption greater than 250 MWh, should be eligible for a transition rate under the Regulation. EEC's submitted that CCG's approach would require an amendment to the definition of "eligible customer" set out in the Regulation, which clearly restricts the definition of eligible customers other than rate classification customers to those customers whose annual consumption at a site is less than 250 MWh.

11.3 Views of the Interveners

CCG

The CCG suggested that their concerns could be addressed if EEC included in its tariff the following definition:

> Residential rate classification customer, for the purposes of determining eligibility for a transition rate under the Regulated Default Supply Regulation, AR-168/2003, means all buildings or complexes that are primarily residential, including seniors' residences, long-term care facilities, residential condominiums and apartments.[28]

CCA

The CCA expressed concerns that any expansion of the definition of "residential rate classification" should be subject to a no-harm test such that customers contained in the existing "residential rate classification" should not have to bear additional costs that may result from the expanded definition. CCA noted the administrative challenge of determining what proportion of a building must be used for residential purposes before being included in the "residential rate classification" for the RRT and/or DT tariff would also be considerable. However, the CCA encouraged the RRT and/or DT providers to explore the possibility of arriving at a definition that applies to those seeking it.

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[28] Tr pages 703 & 864

11.4 Views of the Board

EEC, on behalf of EPC, is required by section 103 of the EUA to prepare a RRT "for the purpose of recovering the prudent costs of providing electricity services to eligible customers." The issue raised by the CCG arose originally from the eligibility requirements prescribed by the *RDS Regulation* as well as the respective entitlements to "transition" or "flow-through" rates for rate classification customers and "non-rate classification customers set out in that Regulation. As already noted in the Introduction to this section of the Decision, however, no issue remains in relation to CCG members with forecast annual consumption less than 250 MWh/year, whether they are rate classification customers or non-rate classification customers. Under the *RDS Amendment Regulation*, those customers are now entitled to a transition rate through to June 30, 2006.

Accordingly, the only issue remaining for the Board's consideration is whether any member of the CCG whose reasonably forecast consumption of electric energy in 2004 may, in the future, exceed 250 MWh/year can be an "eligible customer" for purposes of EEC's 2004 RRT.

Setting up the distinction between "rate classification and "non-rate classification" customers, the definition of "eligible customer" is set out in section 1(1)(b) of the *RDS Regulation*:

> "eligible customer" means:
>
> (i) a rate classification customer, and
>
> (ii) any other customer, if the owner's reasonable forecast of the customer's annual consumption of electric energy at a site is less than 250 megawatt hours of electric energy at that site;

Only eligible customers according to this definition are entitled to receive service under EEC's RRT. A customer must, therefore, be either a "rate classification customer" referred to in section 1(1)(b)(i) or a customer falling within the residual class described in section 1(1)(b)(ii), which can conveniently be described as "non-rate classification customers". Annual consumption of less than 250 MWh per site is expressly prescribed in relation to non-rate classification customers.

"Rate classification customer" is specifically defined in section 1(1)(e) of the *RDS Regulation*:

> (e) "rate classification customer" means
>
> (i) a residential rate classification customer,
>
> (ii) a farm rate classification customer, or
>
> (iii) an irrigation rate classification customer,
>
> as defined in a regulated rate tariff.

The Board was advised that the current members of the CCG currently each consume less than 250 MWh/year. However, it may be that current or possible future members of the CCG may, in the future, be forecast to consume more than 250 MWh/year.[29] The argument of the CCG was that all of its members could be deemed to be eligible for RRT service, regardless of their forecast annual consumption, if they were included in the definition of "residential rate classification customer" in EEC's 2004 RRT. The question to be decided by the Board, therefore, is whether a CCG member can be considered either a rate classification customer or a non-rate classification customer so as to be RRT-eligible under the terms of the *RDS Regulation*, notwithstanding that a member's annual consumption is in excess of 250 MWh.

In the Board's view, the definitions of "rate classification customer" and "eligible customer", which are unaffected by the *RDS Amendment Regulation*, must be read together and in context. First, the Board considers it reasonable to assume that the drafters of the *RDS Regulation* would have been mindful of the definitions of residential, farm and irrigation customers contained in utility tariffs at the time of drafting. The Board notes that there are no farm or irrigation customers in the EPC service area, and that the average annual consumption for a residential customer in the EPC service area is in the range of 7 to 8 MWh/year, significantly below the 250 MWh/year "non-rate classification" limitation. Second, it appears clear to the Board that the two parts of the definition of "eligible customer" cannot be read in isolation from each other and that the 250 MWh/year limitation is implicit in the reference to "rate classification customer" in the definition of "eligible customer". To accept the argument that any customer can be made eligible for the transition or flow-through rate by simply designating that customer to be a "residential", "farm" or "irrigation" customer appears to fly in the face of the clear intent of the *RDS Regulation*.

In light of these considerations, the Board is of the view that customers with forecast annual consumption in excess of 250 MWh were not intended to be eligible for any rate under a RRT. Accordingly, the Board considers that CCG customers consuming more than 250 MWh/year are required either to negotiate a contract with a retailer or to take service from a default supplier under the default rate. As noted by the Board during the hearing, although not obligated to do so, the appointed default provider (in this case EEC) may be able to conclude a satisfactory arrangement with these ineligible customers under the unregulated default supply rate.

12 BILLING OF EEC DISTRIBUTION TARIFF CHARGES

The *RDS Regulation* indicates that:

> **9(1)** Effective July 1, 2004, for regulated rate customers,
>
> (a) both the electric energy charge and the delivery charge to customers in a billing period must be based on common consumption data for that billing period, and
>
> (b) at sites where electric energy consumption is metered, at least twice each calendar year the charge for electric energy for a billing period must be based on an actual meter reading.

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[29] The Board notes that the St. Michael's Long Term Care Center Society, a member of the Edmonton Extended Care Group, (a sister organization to the CCG) consumes in excess of 250 MWh/year.

EEC indicated that it intended to synchronize the billing data as required by the *RDS Regulation* effective July 1, 2004.

For the first six months of 2004, EEC proposed to utilize its historical approach to billing the total delivery charges under which the System Access Service and Distribution Access Service charges are established on a forecast basis with no deferral accounts. As a result, EEC did not propose to reconcile the differences between total delivery charges collected from customers and total delivery charges paid to EPC.

12.1 Views of the Board

The Board considers that EEC's approach of not reconciling the differences between total delivery charges collected from customers and total delivery charges paid to EPC is a continuation of past practice and a practical alternative until synchronization of bills is implemented. Accordingly the Board will allow EEC's historical approach to be used until July 1, 2004, the date required by the *RDS Regulation* for synchronization.

13 EEC-EPC RRT ARRANGEMENT

13.1 Background

Since January 1, 2001, EEC has provided regulated rate service (formerly regulated rate option or RRO service) in the EPC service area pursuant to an arrangement between EPC and EEC approved by Calgary City Council. The EUA and the RDS Regulation require an authorization by an owner of an electric distribution system for a third party to provide RRT service to be approved by the owner's regulatory authority. The question arose whether the Board was now required to approve the arrangement by which EPC authorized EEC to provide RRT service.

13.2 Views of the Applicant

On June 14, 2000, the Board of Directors of EPC approved the appointment of EEC to provide regulated rate services on behalf of EPC in EPC's service territory (Appointment). That Appointment was confirmed by resolution of EPC's shareholder, Calgary City Council, on December 11, 2000. The Appointment was in the form of a "Contract for Services" between EPC and EEC and was effective January 1, 2001.[30] EPC submitted that by operation of section 155 of the EUA the December 11, 2000 approval by Calgary City Council continues in effect and no further approval of the Appointment is required.

13.3 Views of the Interveners

Calgary

Calgary submitted that the issue was whether the new EUA has in fact refreshed or created a different circumstance with respect to just who the regulatory authority might be over the activities of EPC and EDI, going forward as of January 1, 2004. Calgary indicated that the Board must make a decision on what jurisdiction it has, when it has that jurisdiction, and how it must exercise that jurisdiction on a consistent basis in respect of the appointments.

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[30] EEC RRT Application, Section 2, page 1; BR-EEC.14(a)-(b); Tr pages 554-555.

CCA

The CCA took the position that section 11 of the *RDS Regulation* appeared to refresh the issue requiring that EPC to bring a formal application for an arrangement for EEC to act as the RRT service provider. The CCA submitted that that the Board should be able to look at and review applications, such as this Appointment, particularly where they are conducted with an affiliate or as between affiliated companies.

13.4 Views of the Board

The Board notes that Calgary City Council approved the appointment of EEC as the regulated rate provider in the EPC service territory pursuant to resolution dated December 11, 2000, with the Appointment being effective January 1, 2001. The approval of the Appointment was made pursuant to sections 15 and 16 of the *Regulated Rate Option Regulation* (*RRO Regulation*) under the terms of the EUA in force prior to June 1, 2003, when the present EUA came into effect. The *RRO Regulation*, like section 104 of the present EUA, effectively allowed the owner of an electric distribution system to authorize a third party to carry out the owner's obligations to provide regulated rate service in the owner's service territory.

Although EDI considered it appropriate to apply for approval of a new arrangement authorizing EESI as its RRT provider,[31] EEC has taken the position that no further approval by the Board of its appointment of EEC is required by virtue of section 155 of the new EUA. Section 155 provides as follows:

> 155 Any approval, order, direction or other determination and any instrument relating to
>
> (a) an electric utility,
> (b) the owner of an electric utility, or
> (c) the Transmission Administrator
>
> made under the *Public Utilities Board Act*, the *Hydro and Electric Energy Act*, the *Electric Utilities Act*, SA 1995 cE-5.5, or the *Electric Utilities Act*, RSA 2000 cE-5, before the coming into force of this section does not cease to have effect as a result of the coming into force of this Act.

Although under the old EUA, the owner of a municipal electric distribution system was not included in the definition of an "electric utility", the provisions of the *RRO Regulation* applied to owners of electric distribution systems in general, including municipal owners such as EPC. However, since section 155 appears in the present EUA, and the present EUA defines "electric utility" in such a way that EPC is included in the definition, the Board is of the view that the approval by Calgary City Council of the Appointment could arguably fall within the contemplation of section 155 of the EUA.

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[31] The Board approved EDI's arrangement with EESI in Decision 2003-085.

However, the Board notes the specific wording of both section 104 of the EUA and section 11 of the *RDS Regulation*. Section 104 provides that:

> **104(1)** An owner of an electric distribution system may make arrangements under which other persons perform any or all of the duties or functions of the owner under ***this Act and the regulations.***

Section 11 of the *RDS Regulation* requires approval of these arrangements in the following terms:

> **11** An arrangement made by an owner under section 104 of the Act under which another person is authorized to perform any or all of the duties or functions of the owner under ***this Regulation*** has no effect unless the arrangement is approved by the owner's regulatory authority.

In the Board's view, there is some question whether the Appointment relates to

(a) an "electric utility" since at the time the Appointment was approved, EPC was not an "electric utility" under the EUA, notwithstanding the terms of the current EUA; and

(b) the functions of EPC as owner under "this Regulation", meaning the current *RDS Regulation* rather than the *RRO Regulation* as it stood prior to June 1, 2003.

There is also some question whether section 155 of the EUA was intended to apply in cases where there has been a change of regulatory authority. Arguably, section 155 was meant to preserve only prior approvals by the same regulatory authority. Otherwise, a new regulatory authority might find itself in a difficult position of being unable to achieve the purposes of the transfer of jurisdiction from one authority to another.

In the Board's view, this lack of clarity and EPC's decision not to apply for approval of a current arrangement with EEC is undesirable, particularly since the Board is now EPC's regulatory authority. In the Board's view, it would be preferable for EPC to apply for Board approval of the Appointment, or a similar arrangement, pursuant to section 11 of the RDS Regulation as soon as possible, so that the Board may deal with any such application as part of the final proceeding to commence in March 2004.

Notwithstanding the above, the Board is prepared to accept that the Appointment does not cease to have effect as a result of the coming into force of the EUA. For clarity, the Board considers that the decision rests with EPC whether to apply for Board approval of the Appointment, or a similar arrangement, pursuant to section 11 of the *RDS Regulation*.

14 SUMMARY OF BOARD APPROVALS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. Accordingly, the Board approves the fixed energy charge component of EEC's RCC rate of $0.05353/kWh on a final basis for the first quarter of 2004. 6
2. Accordingly, the Board approves an interim, refundable Residential Energy Charge of $0.05620/kWh effective January 1, 2004. 6
3. Accordingly, the Board approves the fixed charge component of EEC's NRCC transition rate of $0.05173/kWh for the first quarter of 2004. 19
4. Accordingly, the Board approves an interim, refundable Commercial Energy Charge of $0.05437/kWh effective January 1, 2004. 19
5. Accordingly, the Board approves a return margin on an interim basis of 2% for both energy and non-energy components of EEC's interim tariff. The Board will determine the final level of the margin in the final tariff proceeding. 30

15 SUMMARY OF BOARD DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. Accordingly the Board directs EEC to file for acknowledgement the justification for each quarterly adjustment to its RCC EMCR, including full disclosure of the calculations supporting the adjustment using the current reporting requirement as approved by the EURC for 2003 before the change in the RCC EMCR is made. 10
2. Accordingly the Board directs EEC to file for acknowledgement the justification for each quarterly adjustment to its NRCC EMCR, including full disclosure of the calculations supporting the adjustment using the current reporting requirement as approved by the EURC for 2003 before the change in the NRCC EMCR is made. 20
3. Accordingly, the Board directs EEC to file a report, on or before March 1, 2004, setting out the results of the discussions and any consensus reached. The Board considers this matter to be both urgent and significant and would be amenable to any consensus being formalized by way of a negotiated settlement respecting a revised EEC Energy procurement plan, notwithstanding the views expressed by the Board in Decision 2003-096. The Board would consider the report and any consensus option, including any consensus on return margin, prior to April 1, 2004. If no return margin was arrived at respecting any consensus option, the appropriate return margin associated with the consensus option would be deferred to the final proceeding. 36

16 ORDER

For and subject to the reasons set out in this Decision, the Board:

1) Approves as interim refundable rates the Price Schedules attached as Schedule A of this Decision.
2) Approves on an interim basis the Terms and Conditions attached as Schedule B of this Decision.
3) Approves on an interim basis the Fee Schedule attached as Schedule C of this Decision.

Dated in Calgary, Alberta on December 5, 2003.

ALBERTA ENERGY AND UTILITIES BOARD

N. W. MacDonald

N. W. MacDonald, P. Eng.
Presiding Member

R Lock.

R. G. Lock, P. Eng.
Member

J. I. Douglas, FCA
Member

APPENDIX 1 – HEARING PARTICIPANTS

Principals and Representatives (Abbreviations Used in Report)	Witnesses
ENMAX Power Corporation (EPC) and ENMAX Energy Corporation (EEC) L. A. Cusano, Esq. D. A. Wood	EEC Dr. Ed Overcast, PhD Stuart Berry J. R. Joyce Bob Cummings Brad Thompson Allan Buchignani EPC K. Phillips Brad Thompson Allan Buchignani
EPCOR Energy Services (EESI) and EPCOR Distribution Inc. (EDI) J. M. Liteplo, Esq. D. E. Crowther, Esq.	EESI B. DeNeve Brian Gerdes EDI B. DeNeve Rick Cowburn
ATCO Electric Limited L. G. Keough, Esq. Kristen Lozynski, Esq.	
Calgary Industrial Group and Calgary Building Owners Coalition L. L. Manning, Esq	
Consumers Coalition of Alberta J. A. Wachowich	
Direct Energy Preferred P. Nigol	
Industrial Power Consumer Association M. S. Forster, Esq. Dan B. Macnamara	
Care Center Group (CCG), Edmonton Members St. Michael's Long Term Care Center Society, Devonshire Care Centre and Good Samaritan Roger Bellows A. O. Ackroyd, Q. C	

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Care Center Group (CCG) Calgary Members Glamorgan Care Center, Mayfair Care Centre, Newport Harbour Care Centre Roger Bellows A. O. Ackroyd, Q. C	
Public Institutional Consumers of Alberta Nancy J. McKenzie, Esq Raj Retnanandan	
The City of Calgary D. I. Evanchuk, Esq.	
The Cities of Lethbridge, Red Deer, and University of Alberta Phyllis A. Smith, Q. C.	
Utilities Consumer Advocate C. R. McCreary Roger W. Jackson	
Board Panel N. W. MacDonald, P. Eng. R. G. Lock, P. Eng. J. I. Douglas, FCA	
Board Counsel Allan Domes, Esq.	
Board Staff Brian Ploof Kim Koshelanyk Wayne Taylor	

APPENDIX 2 – CUSTOMER BILL COMPARISONS

"Residential (R100)
Bill Comparison.xls"

(Consists of 5 pages)

"Commercial (R200)
Bill Comparison.xls"

(Consists of 5 pages)

"Commercial (R350)
Bill Comparison.xls"

(Consists of 5 pages)

ENMAX Power Corporation

Changes From Final 2002 Bills @ October 1 to Final 2003 Bills @ October 1

	A	B	C	D	E	F	G	h	I	J	J	K	M	N	O	P
Rate Class Description	Final 2002 @ October 1 ¢/kWh	Energy Cost Change ¢/kWh	Admin Charge Change ¢/kWh	MCAF Cost Change ¢/kWh	Final 2003 @ January 1 ¢/kWh	EMCR Cost Change ¢/kWh	Final 2003 @ April 1 ¢/kWh	Energy Cost Change ¢/kWh	Admin Charge Change ¢/kWh	MCAF Cost Change ¢/kWh	EMCR Cost Change ¢/kWh	Final 2003 @ July 1 ¢/kWh	EMCR Cost Change ¢/kWh	Final 2003 @ October 1 ¢/kWh	Change (N - A) ¢/kWh	Change O/A %
Residential Service	11.76	(0.12)	(0.12)	(0.01)	11.51	1.24	12.75	(0.50)	(0.07)	(0.06)	(2.15)	9.97	1.51	11.48	(0.28)	(2.4%)

Note:
- Final 2002 Bills are for the 2002 calendar year.
- Final 2003 Bills are for the 2003 calendar year.
- Monthly consumption was assumed to be constant.

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

ENMAX Power Corporation

Changes From Final 2003 Bills @ October 1 to Final 2004 Bills @ January 1

	A	B	C	D	E	F	G	H	I
Rate Class Description	**Final 2003 @ October 1 ¢/kWh**	Energy Cost Change ¢/kWh	Admin Charge Change ¢/kWh	DT Cost Change ¢/kWh	LAF Cost Change ¢/kWh	EMCR Cost Change ¢/kWh	**Final 2004 @ January 1 ¢/kWh**	**Change (G - A) ¢/kWh**	**Change H / A %**
Residential Service	**11.48**	**0.14**	**0.45**	**0.00**	**0.02**	**(0.32)**	**11.77**	**0.29**	**2.5%**

Note: - Final 2003 Bills are for the 2003 calendar year.
- Final 2004 Bills are for the 2004 calendar year.
- Monthly consumption was assumed to be constant.

ENMAX Power Corporation

Changes From Final 2004 Bills @ January 1 to Final 2005 Bills @ January 1

	A	B	C	D	E	F	G	H	I
Rate Class Description	**Final 2004 @ January 1 ¢/kWh**	EMCR Cost Change ¢/kWh	**Final 2004 @ April 1 ¢/kWh**	Energy Cost Change ¢/kWh	Administration Charge Change ¢/kWh	EMCR Cost Change ¢/kWh	**Final 2005 @ January 1 ¢/kWh**	**Change (D - A) ¢/kWh**	**Change $\frac{E}{A}$ %**
Residential Service	**11.77**	(0.28)	**11.49**	0.00	0.00	0.00	**11.49**	**(0.28)**	**(2.4%)**

Note:
- Final 2004 Bills are for the 2004 calendar year.
- Final 2005 Bills are for the 2005 calendar year.
- Monthly consumption was assumed to be constant.

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

ENMAX Power Corporation (EPC)
2003 - 2004 Residential Rate Continuity Schedule

Line No.	Rate Component	Line Reference	Effective Date	Low Usage		Typical Usage		High Usage	
			Unit	Customer Usage Level					
			kWh	300		625		900	
			Mo.	1		1		1	
				Costs for Each Usage Level ($/month) and Percentage Change Relative to Specified Row					
1	**Final Bill - 2002**	[1]	Oct 1, 02	**$44.03**		**$73.50**		**$98.44**	
2.1	Changes between final 2003 bills & 2003 Base Rate								
2.2	Energy Cost	[2]	Jan 1, 03	($0.34)	(0.8%)	($0.72)	(1.0%)	($1.04)	(1.1%)
2.3	Administration Charge	[2]	Jan 1, 03	($0.75)	(1.7%)	($0.75)	(1.0%)	($0.75)	(0.8%)
2.4	Municipal Consent and Access Fee	[2]	Jan 1, 03	($0.04)	(0.1%)	($0.08)	(0.1%)	($0.11)	(0.1%)
3	**Base Rate - Q1 2003**	[2]	Jan 1, 03	**$42.90**	**(2.6%)**	**$71.95**	**(2.1%)**	**$96.54**	**(1.9%)**
3.1	Changes between Base Rate - Q1 2003 & Base Rate - Q2 2003								
3.2	EMCR	[3]	Apr 1, 03	$3.71	8.6%	$7.72	10.7%	$11.12	11.5%
4	**Base Rate - Q2 2003**	[3]	Apr 1, 03	**$46.60**	**8.6%**	**$79.67**	**10.7%**	**$107.65**	**11.5%**
4.1	Changes between Base Rate - Q2 2003 & Base Rate - Q3 2003								
4.2	Energy Cost	[4]	Jul 1, 03	($1.51)	(3.2%)	($3.14)	(3.9%)	($4.53)	(4.2%)
4.3	Administration Charge	[4]	Jul 1, 03	($0.45)	(1.0%)	($0.45)	(0.6%)	($0.45)	(0.4%)
4.4	Municipal Consent and Access Fee	[4]	Jul 1, 03	($0.17)	(0.4%)	($0.35)		($0.50)	
4.5	EMCR	[4]	Jul 1, 03	($6.45)	(13.8%)	($13.43)	(16.9%)	($19.34)	(18.0%)
5	**Base Rate - Q3 2003**	[4]	Jul 1, 03	**$38.03**	**(18.4%)**	**$62.30**	**(21.8%)**	**$82.83**	**(23.1%)**
5.1	Changes between Base Rate - Q3 2003 & Base Rate - Q4 2003								
5.2	EMCR	[5]	Oct 1, 03	$4.54	11.9%	$9.45	15.2%	$13.61	16.4%
6	**Final Bill - 2003**	[5]	Oct 1, 03	**$42.57**	**11.9%**	**$71.75**	**15.2%**	**$96.44**	**16.4%**
6.1	Changes between Base Rate - Q4 2003 & Predicted Base - Rate 2004								
6.2	Energy Cost	[6]	Jan 1, 04	$0.41	6.6%	$0.86	1.2%	$1.24	1.3%
6.3	Administration Charge	[6]	Jan 1, 04	$2.81	0.1%	$2.81	3.9%	$2.81	2.9%
6.4	Distribution and Transmission Cost	[6]	Jan 1, 04	$0.02	0.1%	$0.02	0.0%	$0.02	0.0%
6.5	Local Access Fee (formerly Municipal Consent & Access Fee)	[6]	Jan 1, 04	$0.05	0.1%	$0.10	0.1%	$0.14	0.1%
6.6	EMCR	[6]	Jan 1, 04	($0.95)	(2.2%)	($1.99)	(2.8%)	($2.86)	(3.0%)
7	**Predicted Bill - 2004 Q1**	[6]	Jan 1, 04	**$44.91**	**5.5%**	**$73.55**	**2.5%**	**$97.79**	**1.4%**
7.1	Changes between Predicted Bill - Q1 2004 & Q2-Q4 2004								
7.2	EMCR	[7]	Jan 1, 04	($0.84)	(2.0%)	($1.75)	(2.4%)	($2.52)	(2.6%)
8	**Predicted Bill - 2004 (Q2 - Q4)**	[7]	Jan 1, 04	**$44.07**	**(1.9%)**	**$71.80**	**(2.4%)**	**$95.27**	**(2.6%)**

Notes: Monthly consumption was assumed to be constant.
There was a one-time credit of $2.70 per customer in July 2003 to rebate customers for the EURC final decision on the Administration Charge.
Differences due to rounding.

Residential (R100)

Consumption: 625 **kWh/month**

	Unit	2002	2003				2004			
			Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Input Parameters:										
Energy Price	$/kWh	0.06100	0.05985	0.05985	0.05482	0.05482	0.05620	0.05620	0.05620	0.05620
Administration Charge	$/day	0.2236	0.1989	0.1989	0.1841	0.1841	0.2756	0.2756	0.2756	0.2756
System Access Service Charge	$/day	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000	0.1000
System Access Usage Charge	$/kWh	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029
Distribution Access Service Charge	$/day	0.1968	0.1968	0.1968	0.1968	0.1968	0.1968	0.1968	0.1968	0.1968
Distribution Access Usage Charge	$/kWh	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Energy Market Charge/Refund	$/kWh	-	-	0.01235	(0.00914)	0.00598	0.00280	-	-	-
Deficiency Rider 2000	$/month	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657
Typical Customer Bill Presentation										
Electric Energy Charge										
Administration Charge		6.80	6.05	6.05	5.60	5.60	8.41	8.41	8.41	8.41
Electric Energy Charge		38.13	37.41	37.41	34.26	34.26	35.13	35.13	35.13	35.13
Electricity Market Charge/Refund		-	-	7.72	(5.71)	3.74	1.75	-	-	-
Delivery Charges										
System Access Service Charge		4.87	4.87	4.87	4.87	4.87	4.88	4.88	4.88	4.88
Distribution Access Service Charge		13.34	13.34	13.34	13.34	13.34	13.36	13.36	13.36	13.36
Deficiency Rider 2000		4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11
Local Access Fee (MCAF)		6.26	6.18	6.18	5.83	5.83	5.93	5.93	5.93	5.93
Total Monthly Charge		73.50	71.95	79.67	62.30	71.75	73.55	71.80	71.80	71.80

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

Residential (R100)

	Unit		2003				2004			
		2002	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Consumption:	625 kWh/month									
Input Parameters:										
Energy Price	$/kWh	0.06100	0.05985	0.05985	0.05482	0.05482	**0.05620**	**0.05620**	**0.05620**	**0.05620**
Administration Charge	$/day	0.2236	0.1989	0.1989	0.1841	0.1841	**0.2756**	**0.2756**	**0.2756**	**0.2756**
System Access Service Charge	$/day	0.1000	0.1000	0.1000	0.1000	0.1000	**0.1000**	**0.1000**	**0.1000**	**0.1000**
System Access Usage Charge	$/kWh	0.0029	0.0029	0.0029	0.0029	0.0029	**0.0029**	**0.0029**	**0.0029**	**0.0029**
Distribution Access Service Charge	$/day	0.1968	0.1968	0.1968	0.1968	0.1968	**0.1968**	**0.1968**	**0.1968**	**0.1968**
Distribution Access Usage Charge	$/kWh	0.01	0.01	0.01	0.01	0.01	**0.01**	**0.01**	**0.01**	**0.01**
Energy Market Charge/Refund	$/kWh	-	-	0.01235	(0.00914)	0.00598	**0.00280**	**-**	**-**	**-**
Deficiency Rider 2000	$/month	0.00657	0.00657	0.00657	0.00657	0.00657	**0.00657**	**0.00657**	**0.00657**	**0.00657**
Typical Customer Bill Presentation										
Electric Energy Charge										
Administration Charge		6.80	6.05	6.05	5.60	5.60	8.41	8.41	8.41	8.41
Electric Energy Charge		38.13	37.41	37.41	34.26	34.26	35.13	35.13	35.13	35.13
Electricity Market Charge/Refund		-	-	7.72	(5.71)	3.74	1.75	-	-	-
Delivery Charges										
System Access Service Charge		4.87	4.87	4.87	4.87	4.87	4.88	4.88	4.88	4.88
Distribution Access Service Charge		13.34	13.34	13.34	13.34	13.34	13.36	13.36	13.36	13.36
Deficiency Rider 2000		4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11	4.11
Local Access Fee (MCAF)		6.26	6.18	6.18	5.83	5.83	5.93	5.93	5.93	5.93
Total Monthly Charge		73.50	71.95	79.67	62.30	71.75	73.55	71.80	71.80	71.80

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

ENMAX Power Corporation

Changes From Final 2002 Bills @ October 1 to Final 2003 Bills @ October 1

	A	B	C	D	E	F	G	h	I	J	J	K	M	N	O	P
Rate Class Description	**Final 2002 @ October 1 ¢/kWh**	Energy Cost Change ¢/kWh	Admin Charge Change ¢/kWh	MCAF Cost Change ¢/kWh	**Final 2003 @ January 1 ¢/kWh**	EMCR Cost Change ¢/kWh	**Final 2003 @ April 1 ¢/kWh**	Energy Cost Change ¢/kWh	Admin Charge Change ¢/kWh	MCAF Cost Change ¢/kWh	EMCR Cost Change ¢/kWh	**Final 2003 @ July 1 ¢/kWh**	EMCR Cost Change ¢/kWh	**Final 2003 @ October 1 ¢/kWh**	**Change (N - A) ¢/kWh**	**Change O/A %**
Commercial Service (R200)	9.75	(0.12)	(0.03)	(0.01)	9.59	1.24	10.82	(0.50)	(0.02)	(0.06)	(2.15)	8.10	1.51	9.61	(0.13)	(1.4%)

Note:
- Final 2002 Bills are for the 2002 calendar year.
- Final 2003 Bills are for the 2003 calendar year.
- Monthly consumption was assumed to be constant.

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

ENMAX Power Corporation

Changes From Final 2003 Bills @ October 1 to Final 2004 Bills @ January 1

	A	B	C	D	E	F	G	H	I
Rate Class Description	**Final 2003 @ October 1 ¢/kWh**	Energy Cost Change ¢/kWh	Admin Charge Change ¢/kWh	DT Cost Change ¢/kWh	LAF Cost Change ¢/kWh	EMCR Cost Change ¢/kWh	**Final 2004 @ January 1 ¢/kWh**	**Change (G - A) ¢/kWh**	**Change H / A %**
Commercial Service (R200)	**9.61**	**(0.04)**	**0.21**	**0.00**	**(0.00)**	**(0.32)**	**9.45**	**(0.16)**	**(1.7%)**

Note:
- Final 2003 Bills are for the 2003 calendar year.
- Final 2004 Bills are for the 2004 calendar year.
- Monthly consumption was assumed to be constant.

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

ENMAX Power Corporation

Changes From Final 2004 Bills @ January 1 to Final 2005 Bills @ January 1

	A	B	C	D	E	F	G	H	I
Rate Class Description	**Final 2004 @ January 1 ¢/kWh**	EMCR Cost Change ¢/kWh	**Final 2004 @ April 1 ¢/kWh**	Energy Cost Change ¢/kWh	Administration Charge Change ¢/kWh	EMCR Cost Change ¢/kWh	**Final 2005 @ January 1 ¢/kWh**	**Change (D - A) ¢/kWh**	**Change $\frac{E}{A}$ %**
Commercial Service (R200)	**9.45**	(0.28)	**9.17**	0.00	0.00	0.00	**9.17**	**(0.28)**	**(3.0%)**

Note:
- Final 2004 Bills are for the 2004 calendar year.
- Final 2005 Bills are for the 2005 calendar year.
- Monthly consumption was assumed to be constant.

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

ENMAX Power Corporation (EPC)
2003 - 2004 Commercial Rate Continuity Schedule (R200)

			Unit	Customer Usage Level					
				Low Usage		Typical Usage		High Usage	
			kWh	1,375		2,750		3,875	
			Mo.	1		1		1	
Line No.	**Rate Component**	**Line Reference**	**Effective Date**	**Costs for Each Usage Level ($/month) and Percentage Change Relative to Specified Row**					
1	**Final Bill - 2002**	[1]	Oct 1, 02	**$146.78**		**$267.99**		**$367.16**	
2.1	Changes between final 2003 bills & 2003 Base Rate								
2.2	Energy Cost	[2]	Jan 1, 03	($1.58)	(1.1%)	($3.16)	(1.2%)	($4.46)	(1.2%)
2.3	Administration Charge	[2]	Jan 1, 03	($0.75)	(0.5%)	($0.75)	(0.3%)	($0.75)	(0.2%)
2.4	Municipal Consent and Access Fee	[2]	Jan 1, 03	($0.18)	(0.1%)	($0.35)	(0.1%)	($0.50)	(0.1%)
3	**Base Rate - Q1 2003**	[2]	Jan 1, 03	**$144.27**	**(1.7%)**	**$263.72**	**(1.6%)**	**$361.46**	**(1.6%)**
3.1	Changes between Base Rate - Q1 2003 & Base Rate - Q2 2003								
3.2	EMCR	[3]	Apr 1, 03	$16.98	11.8%	$33.96	12.9%	$47.86	13.2%
4	**Base Rate - Q2 2003**	[3]	Apr 1, 03	**$161.25**	**11.8%**	**$297.69**	**12.9%**	**$409.32**	**13.2%**
4.1	Changes between Base Rate - Q2 2003 & Base Rate - Q3 2003								
4.2	Energy Cost	[4]	Jul 1, 03	($6.92)	(4.3%)	($13.83)	(4.6%)	($19.49)	(4.8%)
4.3	Administration Charge	[4]	Jul 1, 03	($0.45)	(0.3%)	($0.45)	(0.2%)	($0.45)	(0.1%)
4.4	Municipal Consent and Access Fee	[4]	Jul 1, 03	($0.77)	(0.5%)	($1.54)		($2.17)	
4.5	EMCR	[4]	Jul 1, 03	($29.55)	(18.3%)	($59.10)	(19.9%)	($83.27)	(20.3%)
5	**Base Rate - Q3 2003**	[4]	Jul 1, 03	**$123.57**	**(23.4%)**	**$222.77**	**(25.2%)**	**$303.94**	**(25.7%)**
5.1	Changes between Base Rate - Q3 2003 & Base Rate - Q4 2003								
5.2	EMCR	[5]	Oct 1, 03	$20.79	16.8%	$41.58	18.7%	$58.59	19.3%
6	**Final Bill - 2003**	[5]	Oct 1, 03	**$144.36**	**16.8%**	**$264.35**	**18.7%**	**$362.53**	**19.3%**
6.1	Changes between Base Rate - Q4 2003 & Predicted Base - Rate 2004								
6.2	Energy Cost	[6]	Jan 1, 04	($0.62)	(0.4%)	($1.24)	(0.5%)	($1.74)	(0.5%)
6.3	Administration Charge	[6]	Jan 1, 04	$5.65	3.9%	$5.65	2.1%	$5.65	1.6%
6.4	Distribution and Transmission Cost	[6]	Jan 1, 04	$0.05	0.0%	$0.05	0.0%	$0.05	0.0%
6.5	Local Access Fee (formerly Municipal Consent & Access Fee)	[6]	Jan 1, 04	($0.06)	(0.0%)	($0.13)	(0.1%)	($0.19)	(0.1%)
6.6	EMCR	[6]	Jan 1, 04	($4.37)	(3.0%)	($8.75)	(3.3%)	($12.52)	(3.4%)
7	**Predicted Bill - 2004 Q1**	[6]	Jan 1, 04	**$145.00**	**0.4%**	**$259.93**	**(1.7%)**	**$353.97**	**(2.4%)**
7.1	Changes between Predicted Bill - Q1 2004 & Q2-Q4 2004								
7.2	EMCR	[7]	Jan 1, 04	($3.85)	(2.7%)	($7.70)	(2.9%)	($10.85)	(3.0%)
8	**Predicted Bill - 2004 (Q2 - Q4)**	[7]	Jan 1, 04	**$141.15**	**(2.7%)**	**$252.23**	**(3.0%)**	**$343.12**	**(3.1%)**

Notes: Monthly consumption was assumed to be constant.
There was a one-time credit of $2.70 per customer in July 2003 to rebate customers for the EURC final decision on the Administration Charge.
DT charges apply to Rate Code R200.
Differences due to rounding.

Commercial (R200)

	Unit	2002	2003				2004			
			Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Consumption:	2750 kWh/month									
Input Parameters:										
Energy Price	$/kWh	0.06100	0.05985	0.05985	0.05482	0.05482	0.05437	0.05437	0.05437	0.05437
Administration Charge	$/day	0.2236	0.1989	0.1989	0.1841	0.1841	0.3688	0.3688	0.3688	0.3688
System Access Service Charge	$/day	0.2064	0.2064	0.2064	0.2064	0.2064	0.2064	0.2064	0.2064	0.2064
System Access Usage Charge	$/kWh	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030
Distribution Access Service Charge	$/day	0.3488	0.3488	0.3488	0.3488	0.3488	0.3488	0.3488	0.3488	0.3488
Distribution Access Usage Charge	$/kWh	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Energy Market Charge/Refund	$/kWh	-	-	0.01235	(0.00914)	0.00598	0.00280	-	-	-
Deficiency Rider 2000	$/month	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657
Typical Customer Bill Presentation										
Electric Energy Charge										
Administration Charge		6.80	6.05	6.05	5.60	5.60	11.25	11.25	11.25	11.25
Electric Energy Charge		167.75	164.59	164.59	150.76	150.76	149.52	149.52	149.52	149.52
Electricity Market Charge/Refund		-	-	33.96	(25.14)	16.45	7.70	-	-	-
Delivery Charges										
System Access Service Charge		14.46	14.46	14.46	14.46	14.46	14.47	14.47	14.47	14.47
Distribution Access Service Charge		36.60	36.60	36.60	36.60	36.60	36.63	36.63	36.63	36.63
Deficiency Rider 2000		18.08	18.08	18.08	18.08	18.08	18.08	18.08	18.08	18.08
Local Access Fee (MCAF)		24.31	23.96	23.96	22.42	22.42	22.29	22.29	22.29	22.29
Total Monthly Charge		**267.99**	**263.72**	**297.69**	**222.77**	**264.35**	**259.93**	**252.23**	**252.23**	**252.23**

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

Commercial (R200)

Consumption: 2750 kWh/month

	Unit	2002	2003				2004			
			Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Input Parameters:										
Energy Price	**$/kWh**	0.06100	0.05985	0.05985	0.05482	0.05482	**0.05437**	**0.05437**	**0.05437**	**0.05437**
Administration Charge	**$/day**	0.2236	0.1989	0.1989	0.1841	0.1841	**0.3688**	**0.3688**	**0.3688**	**0.3688**
System Access Service Charge	**$/day**	0.2064	0.2064	0.2064	0.2064	0.2064	**0.2064**	**0.2064**	**0.2064**	**0.2064**
System Access Usage Charge	**$/kWh**	0.0030	0.0030	0.0030	0.0030	0.0030	**0.0030**	**0.0030**	**0.0030**	**0.0030**
Distribution Access Service Charge	**$/day**	0.3488	0.3488	0.3488	0.3488	0.3488	**0.3488**	**0.3488**	**0.3488**	**0.3488**
Distribution Access Usage Charge	**$/kWh**	0.01	0.01	0.01	0.01	0.01	**0.01**	**0.01**	**0.01**	**0.01**
Energy Market Charge/Refund	**$/kWh**	-	-	0.01235	(0.00914)	0.00598	**0.00280**	**-**	**-**	**-**
Deficiency Rider 2000	**$/month**	0.00657	0.00657	0.00657	0.00657	0.00657	**0.00657**	**0.00657**	**0.00657**	**0.00657**
Typical Customer Bill Presentation										
Electric Energy Charge										
Administration Charge		6.80	6.05	6.05	5.60	5.60	11.25	11.25	11.25	11.25
Electric Energy Charge		167.75	164.59	164.59	150.76	150.76	149.52	149.52	149.52	149.52
Electricity Market Charge/Refund		-	-	33.96	(25.14)	16.45	7.70	-	-	-
Delivery Charges										
System Access Service Charge		14.46	14.46	14.46	14.46	14.46	14.47	14.47	14.47	14.47
Distribution Access Service Charge		36.60	36.60	36.60	36.60	36.60	36.63	36.63	36.63	36.63
Deficiency Rider 2000		18.08	18.08	18.08	18.08	18.08	18.08	18.08	18.08	18.08
Local Access Fee (MCAF)		24.31	23.96	23.96	22.42	22.42	22.29	22.29	22.29	22.29
Total Monthly Charge		**267.99**	**263.72**	**297.69**	**222.77**	**264.35**	**259.93**	**252.23**	**252.23**	**252.23**

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

ENMAX Power Corporation

Changes From Final 2002 Bills @ October 1 to Final 2003 Bills @ October 1

	A	B	C	D	E	F	G	h	I	J	J	K	M	N	O	P
Rate Class Description	Final 2002 @ October 1 ¢/kWh	Energy Cost Change ¢/kWh	Admin Charge Change ¢/kWh	MCAF Cost Change ¢/kWh	Final 2003 @ January 1 ¢/kWh	EMCR Cost Change ¢/kWh	Final 2003 @ April 1 ¢/kWh	Energy Cost Change ¢/kWh	Admin Charge Change ¢/kWh	MCAF Cost Change ¢/kWh	EMCR Cost Change ¢/kWh	Final 2003 @ July 1 ¢/kWh	EMCR Cost Change ¢/kWh	Final 2003 @ October 1 ¢/kWh	Change (N - A) ¢/kWh	Change O / A %
Commercial Service (R350)	8.99	(0.12)	(0.01)	(0.01)	8.85	1.24	10.08	(0.50)	(0.00)	(0.06)	(2.15)	7.37	1.51	8.89	(0.10)	(1.1%)

Note: - Final 2002 Bills are for the 2002 calendar year.
- Final 2003 Bills are for the 2003 calendar year.
- Monthly consumption was assumed to be constant.

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

ENMAX Power Corporation

Changes From Final 2003 Bills @ October 1 to Final 2004 Bills @ January 1

	A	B	C	D	E	F	G	H	I
Rate Class Description	**Final 2003 @ October 1 ¢/kWh**	Energy Cost Change ¢/kWh	Admin Charge Change ¢/kWh	DT Cost Change ¢/kWh	LAF Cost Change ¢/kWh	EMCR Cost Change ¢/kWh	**Final 2004 @ January 1 ¢/kWh**	**Change (G - A) ¢/kWh**	**Change H / A %**
Commercial Service (R350)	8.89	(0.04)	0.06	0.00	(0.00)	(0.32)	8.57	(0.31)	(3.5%)

Note:
- Final 2003 Bills are for the 2003 calendar year.
- Final 2004 Bills are for the 2004 calendar year.
- Monthly consumption was assumed to be constant.

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

ENMAX Power Corporation

Changes From Final 2004 Bills @ January 1 to Final 2005 Bills @ January 1

	A	B	C	D	E	F	G	H	I
Rate Class Description	**Final 2004 @ January 1 ¢/kWh**	EMCR Cost Change ¢/kWh	**Final 2004 @ April 1 ¢/kWh**	Energy Cost Change ¢/kWh	Administration Charge Change ¢/kWh	EMCR Cost Change ¢/kWh	**Final 2005 @ January 1 ¢/kWh**	**Change (D - A) ¢/kWh**	**Change $\frac{E}{A}$ %**
Commercial Service (R350)	**8.57**	(0.28)	**8.29**	0.00	0.00	0.00	**8.29**	**(0.28)**	**(3.3%)**

Note:
- Final 2004 Bills are for the 2004 calendar year.
- Final 2005 Bills are for the 2005 calendar year.
- Monthly consumption was assumed to be constant.

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

ENMAX Power Corporation (EPC)
2003 - 2004 Commercial Rate Continuity Schedule (R350)

			Unit	Customer Usage Level					
				Low Usage		Typical Usage		High Usage	
			kWh	4,920		10,250		15,550	
			Mo.	1		1		1	
				15.24				48.17	
Line No.	**Rate Component**	**Line Reference**	**Effective Date**	**Costs for Each Usage Level ($/month) and Percentage Change Relative to Specified Row**					
1	**Final Bill - 2002**	[1]	Oct 1, 02	**$460.13**		**$921.15**		**$1,379.57**	
2.1	Changes between final 2003 bills & 2003 Base Rate								
2.2	Energy Cost	[2]	Jan 1, 03	($5.66)	(1.2%)	($11.79)	(1.3%)	($17.88)	(1.3%)
2.3	Administration Charge	[2]	Jan 1, 03	($0.75)	(0.2%)	($0.75)	(0.1%)	($0.75)	(0.1%)
2.4	Municipal Consent and Access Fee	[2]	Jan 1, 03	($0.63)	(0.1%)	($1.31)	(0.1%)	($1.99)	(0.1%)
3	**Base Rate - Q1 2003**	[2]	Jan 1, 03	**$453.09**	**(1.5%)**	**$907.30**	**(1.5%)**	**$1,358.95**	**(1.5%)**
3.1	Changes between Base Rate - Q1 2003 & Base Rate - Q2 2003								
3.2	EMCR	[3]	Apr 1, 03	$60.76	13.4%	$126.59	14.0%	$192.04	14.1%
4	**Base Rate - Q2 2003**	[3]	Apr 1, 03	**$513.85**	**13.4%**	**$1,033.89**	**14.0%**	**$1,550.99**	**14.1%**
4.1	Changes between Base Rate - Q2 2003 & Base Rate - Q3 2003								
4.2	Energy Cost	[4]	Jul 1, 03	($24.75)	(4.8%)	($51.56)	(5.0%)	($78.22)	(5.0%)
4.3	Administration Charge	[4]	Jul 1, 03	($0.45)	(0.1%)	($0.45)	(0.0%)	($0.45)	(0.0%)
4.4	Municipal Consent and Access Fee	[4]	Jul 1, 03	($2.75)	(0.5%)	($5.73)		($8.69)	
4.5	EMCR	[4]	Jul 1, 03	($105.73)	(20.6%)	($220.27)	(21.3%)	($334.17)	(21.5%)
5	**Base Rate - Q3 2003**	[4]	Jul 1, 03	**$380.18**	**(26.0%)**	**$755.88**	**(26.9%)**	**$1,129.46**	**(27.2%)**
5.1	Changes between Base Rate - Q3 2003 & Base Rate - Q4 2003								
5.2	EMCR	[5]	Oct 1, 03	$74.39	19.6%	$154.98	20.5%	$235.12	20.8%
6	**Final Bill - 2003**	[5]	Oct 1, 03	**$454.57**	**19.6%**	**$910.86**	**20.5%**	**$1,364.58**	**20.8%**
6.1	Changes between Base Rate - Q4 2003 & Predicted Base - Rate 2004								
6.2	Energy Cost	[6]	Jan 1, 04	($2.21)	(0.5%)	($4.61)	(0.5%)	($7.00)	(0.5%)
6.3	Administration Charge	[6]	Jan 1, 04	$5.65	1.2%	$5.65	0.6%	$5.65	0.4%
6.4	Distribution and Transmission Cost	[6]	Jan 1, 04	$0.07	0.0%	$0.08	0.0%	$0.08	0.0%
6.5	Local Access Fee (formerly Municipal Consent & Access Fee)	[6]	Jan 1, 04	($0.24)	(0.1%)	($0.50)	(0.1%)	($0.77)	(0.1%)
6.6	EMCR	[6]	Jan 1, 04	($15.65)	(3.4%)	($32.60)	(3.6%)	($49.45)	(3.6%)
7	**Predicted Bill - 2004 Q1**	[6]	Jan 1, 04	**$442.19**	**(2.7%)**	**$878.87**	**(3.5%)**	**$1,313.09**	**(3.8%)**
7.1	Changes between Predicted Bill - Q1 2004 & Q2-Q4 2004								
7.2	EMCR	[7]	Jan 1, 04	($13.78)	(3.0%)	($28.70)	(3.2%)	($43.54)	(3.2%)
8	**Predicted Bill - 2004 (Q2 - Q4)**	[7]	Jan 1, 04	**$428.42**	**(3.1%)**	**$850.17**	**(3.3%)**	**$1,269.55**	**(3.3%)**

Notes: Monthly consumption was assumed to be constant.
There was a one-time credit of $2.70 per customer in July 2003 to rebate customers for the EURC final decision on the Administration Charge.
DT charges apply to Rate Code R350.
Differences due to rounding.

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

Commercial (R350)

				2003				2004			
		Unit	2002	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
							30.41667				
Consumption:	10250	**kWh/month**									
	31.75	**kVA/month**									
Input Parameters:											
Energy Price		**$/kWh**	0.06100	0.05985	0.05985	0.05482	0.05482	0.05437	0.05437	0.05437	0.05437
Administration Charge		**$/day**	0.2236	0.1989	0.1989	0.1841	0.1841	0.3688	0.3688	0.3688	0.3688
System Access Facilities Charge		**$/kVA/day**	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427
System Access Usage Charge		**$/kWh**	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030
Distribution Access Service Charge		**$/day**	0.8219	0.8219	0.8219	0.8219	0.8219	0.8219	0.8219	0.8219	0.8219
Distribution Access Facilities Charge		**$/kVA/day**	0.0561	0.0561	0.0561	0.0561	0.0561	0.0561	0.0561	0.0561	0.0561
Distribution Access Usage Charge		**$/kWh**	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076
Energy Market Charge/Refund		**$/kWh**	-	-	0.01235	(0.00914)	0.00598	0.00280	-	-	-
Deficiency Rider 2000		**$/month**	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657
Typical Customer Bill Presentation											
Electric Energy Charge											
Administration Charge			6.80	6.05	6.05	5.60	5.60	11.25	11.25	11.25	11.25
Electric Energy Charge			625.25	613.46	613.46	561.91	561.91	557.29	557.29	557.29	557.29
Electricity Market Charge/Refund			-	-	126.59	(93.69)	61.30	28.70	-	-	-
Delivery Charges											
System Access Service Charge			32.31	32.31	32.31	32.31	32.31	32.32	32.32	32.32	32.32
Distribution Access Service Charge			104.72	104.72	104.72	104.72	104.72	104.79	104.79	104.79	104.79
Deficiency Rider 2000			67.37	67.37	67.37	67.37	67.37	67.37	67.37	67.37	67.37
Local Access Fee (MCAF)			84.69	83.38	83.38	77.65	77.65	77.15	77.15	77.15	77.15
Total Monthly Charge			**921.15**	**907.30**	**1,033.89**	**755.88**	**910.86**	**878.87**	**850.17**	**850.17**	**850.17**
							0.0037	0.0037			
							0.0734	0.0734			
								0.07706			

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

Commercial (R350)

	Unit	2002	2003				2004			
			Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
						30.41667				
Consumption: 10250	**kWh/month**									
31.75	**kVA/month**									
Input Parameters:										
Energy Price	**$/kWh**	0.06100	0.05985	0.05985	0.05482	0.05482	**0.05437**	**0.05437**	**0.05437**	**0.05437**
Administration Charge	**$/day**	0.2236	0.1989	0.1989	0.1841	0.1841	**0.3688**	**0.3688**	**0.3688**	**0.3688**
System Access Facilities Charge	**$/kVA/day**	0.0427	0.0427	0.0427	0.0427	0.0427	**0.0427**	**0.0427**	**0.0427**	**0.0427**
System Access Usage Charge	**$/kWh**	0.0030	0.0030	0.0030	0.0030	0.0030	**0.0030**	**0.0030**	**0.0030**	**0.0030**
Distribution Access Service Charge	**$/day**	0.8219	0.8219	0.8219	0.8219	0.8219	**0.8219**	**0.8219**	**0.8219**	**0.8219**
Distribution Access Facilities Charge	**$/kVA/day**	0.0561	0.0561	0.0561	0.0561	0.0561	**0.0561**	**0.0561**	**0.0561**	**0.0561**
Distribution Access Usage Charge	**$/kWh**	0.0076	0.0076	0.0076	0.0076	0.0076	**0.0076**	**0.0076**	**0.0076**	**0.0076**
Energy Market Charge/Refund	**$/kWh**	-	-	0.01235	(0.00914)	0.00598	**0.00280**	**-**	**-**	**-**
Deficiency Rider 2000	**$/month**	0.00657	0.00657	0.00657	0.00657	0.00657	**0.00657**	**0.00657**	**0.00657**	**0.00657**
Typical Customer Bill Presentation										
Electric Energy Charge										
Administration Charge		6.80	6.05	6.05	5.60	5.60	11.25	11.25	11.25	11.25
Electric Energy Charge		625.25	613.46	613.46	561.91	561.91	557.29	557.29	557.29	557.29
Electricity Market Charge/Refund		-	-	126.59	(93.69)	61.30	28.70	-	-	-
Delivery Charges										
System Access Service Charge		32.31	32.31	32.31	32.31	32.31	32.32	32.32	32.32	32.32
Distribution Access Service Charge		104.72	104.72	104.72	104.72	104.72	104.79	104.79	104.79	104.79
Deficiency Rider 2000		67.37	67.37	67.37	67.37	67.37	67.37	67.37	67.37	67.37
Local Access Fee (MCAF)		84.69	83.38	83.38	77.65	77.65	77.15	77.15	77.15	77.15
Total Monthly Charge		**921.15**	**907.30**	**1,033.89**	**755.88**	**910.86**	**878.87**	**850.17**	**850.17**	**850.17**
						0.0037	0.0037			
						0.0734	0.0734			
							0.07706			

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

SCHEDULE A – EPC RRT PRICE SCHEDULES

"EEC Regulated Rate Tariff.doc"

(Consists of 3 pages)

Regulated Rate Tariff
Rate Code R100 - Residential

This rate schedule is for the provision of electricity services in accordance with the *Regulated Default Supply Regulation* (168/2003) and the *Electric Utilities Act*, S.A. 2003, c. E-5.1.

Applicability

1. This rate applies to "rate classification customers" as defined by the *Regulated Default Supply Regulation* (168/2003). The rate applies within ENMAX Power Corporation, electric distribution system limits for electricity services used exclusively for domestic purposes in separate and permanently metered single-family dwelling units with each unit either separate or incorporated in a common building with other units.
2. As a single phase 2 or 3 wire service supplied at a standard voltage normally available.

Rate

Energy Charge	$0.05620 per kWh
Administration Charge	$0.27560 per day
Energy Market Charge/Refund	As set out in this Tariff
System Access Service Charge	As per Distribution Tariff
Distribution Access Service Charge	As per Distribution Tariff

Local Access Fee (LAF)

A fee set by agreement with the City of Calgary applicable to all services located within the City of Calgary.

Billing Period

Monthly

Terms and Conditions

All services provided under this rate are subject to ENMAX Power Corporation Terms and Conditions for the Regulated Rate Tariff.

This Regulated Rate Tariff will be offered to Residential customers from January 1, 2004 to December 31, 2004.

Regulated Rate Tariff
Rate Code R200 - Small Commercial

This rate schedule is for the provision of electricity services in accordance with the *Regulated Default Supply Regulation* (168/2003) and the *Electric Utilities Act*, S.A. 2003, c. E-5.1. The energy charge is based on the Alberta pool price for energy and is subject to change.

Applicability

1. Commercial Customers are eligible for this rate if a reasonable forecast of the customer's annual consumption of electric energy at a site is less than 250 MWh.
2. Within ENMAX Power Corporation's electric distribution limits for electricity services which are permanently metered and where the energy consumption is less than 5,000 kWh per month.

Rate

Energy Charge	$0.05437 per kWh
Administration Charge	$0.36883 per day
Energy Market Charge/Refund	As set out in this Tariff
System Access Service Charge	As per Distribution Tariff
Distribution Access Service Charge	As per Distribution Tariff

Local Access Fee (LAF)

A fee set by agreement with the City of Calgary applicable to all services located within the City of Calgary.

Billing Period

Monthly

Terms and Conditions

All services provided under this rate are subject to ENMAX Power Corporation Terms and Conditions for Regulated Rate Tariff.

This Regulated Rate Tariff will be offered to Commercial customers commencing from January 1, 2004 to December 31, 2004.

Regulated Rate Tariff
Rate Code R350 - Medium Commercial

This rate schedule is for the provision of electricity services in accordance with the *Regulated Default Supply Regulation* (168/2003) and the *Electric Utilities Act*, S.A. 2003, c. E-5.1. The energy charge is based on the Alberta pool price for energy and is subject to change.

Applicability

1. Commercial Customers are eligible for this rate if a reasonable forecast of the customer's annual consumption of electric energy at a site is less than 250 MWh.
2. Within ENMAX Power Corporation's electric distribution limits for electricity services where the energy consumption is greater than 5,000 kWh per month and a monthly peak demand of 150 kVA was not registered twice in the previous 12 months.

Rate

Energy Charge	$0.05437 per kWh
Administration Charge	$0.36883 per day
Energy Market Charge/Refund	As set out in this Tariff
System Access Service Charge	As per Distribution Tariff
Distribution Access Service Charge	As per Distribution Tariff

Local Access Fee (LAF)

A fee set by agreement with the City of Calgary applicable to all services located within the City of Calgary.

Billing Period

Monthly

Terms and Conditions

All services provided under this rate are subject to ENMAX Power Corporation Terms and Conditions for Regulated Rate Tariff.

The Regulated Rate Tariff will be offered to Commercial customers from January 1, 2004 to December 31, 2004.

SCHEDULE B – EEC RRT TERMS AND CONDITIONS

"EEC RRT T&Cs.doc"

(Consists of 24 pages)

ENMAX Power Corporation

Changes From Final 2002 Bills @ October 1 to Final 2003 Bills @ October 1

	A	B	C	D	E	F	G	h	I	J	J	K	M	N	O	P
Rate Class Description	**Final 2002 @ October 1 ¢/kWh**	Energy Cost Change ¢/kWh	Admin Charge Change ¢/kWh	MCAF Cost Change ¢/kWh	**Final 2003 @ January 1 ¢/kWh**	EMCR Cost Change ¢/kWh	**Final 2003 @ April 1 ¢/kWh**	Energy Cost Change ¢/kWh	Admin Charge Change ¢/kWh	MCAF Cost Change ¢/kWh	EMCR Cost Change ¢/kWh	**Final 2003 @ July 1 ¢/kWh**	EMCR Cost Change ¢/kWh	**Final 2003 @ October 1 ¢/kWh**	**Change (N - A) ¢/kWh**	**Change O / A %**
Commercial Service (R350)	**8.99**	(0.12)	(0.01)	(0.01)	**8.85**	1.24	10.09	(0.50)	(0.00)	(0.06)	(2.15)	7.37	1.51	**8.89**	(0.10)	(1.1%)

Note:
- Final 2002 Bills are for the 2002 calendar year.
- Final 2003 Bills are for the 2003 calendar year.
- Monthly consumption was assumed to be constant.

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

ENMAX Power Corporation

Changes From Final 2003 Bills @ October 1 to Final 2004 Bills @ January 1

	A	B	C	D	E	F	G	H	I
Rate Class Description	**Final 2003 @ October 1 ¢/kWh**	Energy Cost Change ¢/kWh	Admin Charge Change ¢/kWh	DT Cost Change ¢/kWh	LAF Cost Change ¢/kWh	EMCR Cost Change ¢/kWh	**Final 2004 @ January 1 ¢/kWh**	**Change (G - A) ¢/kWh**	**Change H / A %**
Commercial Service (R350)	8.89	(0.04)	0.06	0.00	(0.00)	(0.32)	8.57	(0.31)	(3.5%)

Note:
- Final 2003 Bills are for the 2003 calendar year.
- Final 2004 Bills are for the 2004 calendar year.
- Monthly consumption was assumed to be constant.

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

ENMAX Power Corporation

Changes From Final 2004 Bills @ January 1 to Final 2005 Bills @ January 1

	A	B	C	D	E	F	G	H	I
Rate Class Description	**Final 2004 @ January 1 ¢/kWh**	EMCR Cost Change ¢/kWh	**Final 2004 @ April 1 ¢/kWh**	Energy Cost Change ¢/kWh	Administration Charge Change ¢/kWh	EMCR Cost Change ¢/kWh	**Final 2005 @ January 1 ¢/kWh**	**Change (D - A) ¢/kWh**	**Change $\frac{E}{A}$ %**
Commercial Service (R350)	**8.57**	(0.28)	**8.29**	0.00	0.00	0.00	**8.29**	**(0.28)**	**(3.3%)**

Note:
- Final 2004 Bills are for the 2004 calendar year.
- Final 2005 Bills are for the 2005 calendar year.
- Monthly consumption was assumed to be constant.

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

ENMAX Power Corporation (EPC)
2003 - 2004 Commercial Rate Continuity Schedule (R350)

				Customer Usage Level					
			Unit	Low Usage		Typical Usage		High Usage	
			kWh	4,920		10,250		15,550	
			Mo.	1		1		1	
				15.24				48.17	
Line No.	Rate Component	Line Reference	Effective Date	Costs for Each Usage Level ($/month) and Percentage Change Relative to Specified Row					
1	**Final Bill - 2002**	[1]	Oct 1, 02	**$460.13**		**$921.15**		**$1,379.57**	
2.1	Changes between final 2003 bills & 2003 Base Rate								
2.2	Energy Cost	[2]	Jan 1, 03	($5.66)	(1.2%)	($11.79)	(1.3%)	($17.88)	(1.3%)
2.3	Administration Charge	[2]	Jan 1, 03	($0.75)	(0.2%)	($0.75)	(0.1%)	($0.75)	(0.1%)
2.4	Municipal Consent and Access Fee	[2]	Jan 1, 03	($0.63)	(0.1%)	($1.31)	(0.1%)	($1.99)	(0.1%)
3	**Base Rate - Q1 2003**	[2]	Jan 1, 03	**$453.09**	**(1.5%)**	**$907.30**	**(1.5%)**	**$1,358.95**	**(1.5%)**
3.1	Changes between Base Rate - Q1 2003 & Base Rate - Q2 2003								
3.2	EMCR	[3]	Apr 1, 03	$60.76	13.4%	$126.59	14.0%	$192.04	14.1%
4	**Base Rate - Q2 2003**	[3]	Apr 1, 03	**$513.85**	**13.4%**	**$1,033.89**	**14.0%**	**$1,550.99**	**14.1%**
4.1	Changes between Base Rate - Q2 2003 & Base Rate - Q3 2003								
4.2	Energy Cost	[4]	Jul 1, 03	($24.75)	(4.8%)	($51.56)	(5.0%)	($78.22)	(5.0%)
4.3	Administration Charge	[4]	Jul 1, 03	($0.45)	(0.1%)	($0.45)	(0.0%)	($0.45)	(0.0%)
4.4	Municipal Consent and Access Fee	[4]	Jul 1, 03	($2.75)	(0.5%)	($5.73)		($8.69)	
4.5	EMCR	[4]	Jul 1, 03	($105.73)	(20.6%)	($220.27)	(21.3%)	($334.17)	(21.5%)
5	**Base Rate - Q3 2003**	[4]	Jul 1, 03	**$380.18**	**(26.0%)**	**$755.88**	**(26.9%)**	**$1,129.46**	**(27.2%)**
5.1	Changes between Base Rate - Q3 2003 & Base Rate - Q4 2003								
5.2	EMCR	[5]	Oct 1, 03	$74.39	19.6%	$154.98	20.5%	$235.12	20.8%
6	**Final Bill - 2003**	[5]	Oct 1, 03	**$454.57**	**19.6%**	**$910.86**	**20.5%**	**$1,364.58**	**20.8%**
6.1	Changes between Base Rate - Q4 2003 & Predicted Base - Rate 2004								
6.2	Energy Cost	[6]	Jan 1, 04	($2.21)	(0.5%)	($4.61)	(0.5%)	($7.00)	(0.5%)
6.3	Administration Charge	[6]	Jan 1, 04	$5.65	1.2%	$5.65	0.6%	$5.65	0.4%
6.4	Distribution and Transmission Cost	[6]	Jan 1, 04	$0.07	0.0%	$0.08	0.0%	$0.08	0.0%
6.5	Local Access Fee (formerly Municipal Consent & Access Fee)	[6]	Jan 1, 04	($0.24)	(0.1%)	($0.50)	(0.1%)	($0.77)	(0.1%)
6.6	EMCR	[6]	Jan 1, 04	($15.65)	(3.4%)	($32.60)	(3.6%)	($49.45)	(3.6%)
7	**Predicted Bill - 2004 Q1**	[6]	Jan 1, 04	**$442.19**	**(2.7%)**	**$878.87**	**(3.5%)**	**$1,313.09**	**(3.8%)**
7.1	Changes between Predicted Bill - Q1 2004 & Q2-Q4 2004								
7.2	EMCR	[7]	Jan 1, 04	($13.78)	(3.0%)	($28.70)	(3.2%)	($43.54)	(3.2%)
8	**Predicted Bill - 2004 (Q2 - Q4)**	[7]	Jan 1, 04	**$428.42**	**(3.1%)**	**$850.17**	**(3.3%)**	**$1,269.55**	**(3.3%)**

Notes: Monthly consumption was assumed to be constant.
There was a one-time credit of $2.70 per customer in July 2003 to rebate customers for the EURC final decision on the Administration Charge.
DT charges apply to Rate Code R350.
Differences due to rounding.

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

Commercial (R350)

			2003				2004			
	Unit	**2002**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
						30.41667				
Consumption:	10250 kWh/month									
	31.75 kVA/month									
Input Parameters:										
Energy Price	**$/kWh**	0.06100	0.05985	0.05985	0.05482	0.05482	0.05437	0.05437	0.05437	0.05437
Administration Charge	**$/day**	0.2236	0.1989	0.1989	0.1841	0.1841	0.3688	0.3688	0.3688	0.3688
System Access Facilities Charge	**$/kVA/day**	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427
System Access Usage Charge	**$/kWh**	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030
Distribution Access Service Charge	**$/day**	0.8219	0.8219	0.8219	0.8219	0.8219	0.8219	0.8219	0.8219	0.8219
Distribution Access Facilities Charge	**$/kVA/day**	0.0561	0.0561	0.0561	0.0561	0.0561	0.0561	0.0561	0.0561	0.0561
Distribution Access Usage Charge	**$/kWh**	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076
Energy Market Charge/Refund	**$/kWh**	-	-	0.01235	(0.00914)	0.00598	0.00280	-	-	-
Deficiency Rider 2000	**$/month**	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657
Typical Customer Bill Presentation										
Electric Energy Charge										
Administration Charge		6.80	6.05	6.05	5.60	5.60	11.25	11.25	11.25	11.25
Electric Energy Charge		625.25	613.46	613.46	561.91	561.91	557.29	557.29	557.29	557.29
Electricity Market Charge/Refund		-	-	126.59	(93.69)	61.30	28.70	-	-	-
Delivery Charges										
System Access Service Charge		32.31	32.31	32.31	32.31	32.31	32.32	32.32	32.32	32.32
Distribution Access Service Charge		104.72	104.72	104.72	104.72	104.72	104.79	104.79	104.79	104.79
Deficiency Rider 2000		67.37	67.37	67.37	67.37	67.37	67.37	67.37	67.37	67.37
Local Access Fee (MCAF)		84.69	83.38	83.38	77.65	77.65	77.15	77.15	77.15	77.15
Total Monthly Charge		**921.15**	**907.30**	**1,033.89**	**755.88**	**910.86**	**878.87**	**850.17**	**850.17**	**850.17**
						0.0037	0.0037			
						0.0734	0.0734			
							0.07706			

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

Commercial (R350)

			2003				2004			
	Unit	2002	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
						30.41667				
Consumption:	10250 kWh/month									
	31.75 kVA/month									
Input Parameters:										
Energy Price	$/kWh	0.06100	0.05985	0.05985	0.05482	0.05482	0.05437	0.05437	0.05437	0.05437
Administration Charge	$/day	0.2236	0.1989	0.1989	0.1841	0.1841	0.3688	0.3688	0.3688	0.3688
System Access Facilities Charge	$/kVA/day	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427	0.0427
System Access Usage Charge	$/kWh	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030
Distribution Access Service Charge	$/day	0.8219	0.8219	0.8219	0.8219	0.8219	0.8219	0.8219	0.8219	0.8219
Distribution Access Facilities Charge	$/kVA/day	0.0561	0.0561	0.0561	0.0561	0.0561	0.0561	0.0561	0.0561	0.0561
Distribution Access Usage Charge	$/kWh	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076	0.0076
Energy Market Charge/Refund	$/kWh	-	-	0.01235	(0.00914)	0.00598	0.00280	-	-	-
Deficiency Rider 2000	$/month	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657	0.00657
Typical Customer Bill Presentation										
Electric Energy Charge										
Administration Charge		6.80	6.05	6.05	5.60	5.60	11.25	11.25	11.25	11.25
Electric Energy Charge		625.25	613.46	613.46	561.91	561.91	557.29	557.29	557.29	557.29
Electricity Market Charge/Refund		-	-	126.59	(93.69)	61.30	28.70	-	-	-
Delivery Charges										
System Access Service Charge		32.31	32.31	32.31	32.31	32.31	32.32	32.32	32.32	32.32
Distribution Access Service Charge		104.72	104.72	104.72	104.72	104.72	104.79	104.79	104.79	104.79
Deficiency Rider 2000		67.37	67.37	67.37	67.37	67.37	67.37	67.37	67.37	67.37
Local Access Fee (MCAF)		84.69	83.38	83.38	77.65	77.65	77.15	77.15	77.15	77.15
Total Monthly Charge		**921.15**	**907.30**	**1,033.89**	**755.88**	**910.86**	**878.87**	**850.17**	**850.17**	**850.17**
						0.0037	0.0037			
						0.0734	0.0734			
							0.07706			

Disclaimer: These calculations are for illustrative purposes only. Actual customer bills may differ.

SCHEDULE A – EPC RRT PRICE SCHEDULES

"EEC Regulated Rate Tariff.doc"

(Consists of 3 pages)

Regulated Rate Tariff
Rate Code R100 - Residential

This rate schedule is for the provision of electricity services in accordance with the *Regulated Default Supply Regulation* (168/2003) and the *Electric Utilities Act*, S.A. 2003, c. E-5.1.

Applicability

1. This rate applies to "rate classification customers" as defined by the *Regulated Default Supply Regulation* (168/2003). The rate applies within ENMAX Power Corporation, electric distribution system limits for electricity services used exclusively for domestic purposes in separate and permanently metered single-family dwelling units with each unit either separate or incorporated in a common building with other units.
2. As a single phase 2 or 3 wire service supplied at a standard voltage normally available.

Rate

Energy Charge	$0.05620 per kWh
Administration Charge	$0.27560 per day
Energy Market Charge/Refund	As set out in this Tariff
System Access Service Charge	As per Distribution Tariff
Distribution Access Service Charge	As per Distribution Tariff

Local Access Fee (LAF)

A fee set by agreement with the City of Calgary applicable to all services located within the City of Calgary.

Billing Period

Monthly

Terms and Conditions

All services provided under this rate are subject to ENMAX Power Corporation Terms and Conditions for the Regulated Rate Tariff.

This Regulated Rate Tariff will be offered to Residential customers from January 1, 2004 to December 31, 2004.

Regulated Rate Tariff
Rate Code R200 - Small Commercial

This rate schedule is for the provision of electricity services in accordance with the *Regulated Default Supply Regulation* (168/2003) and the *Electric Utilities Act*, S.A. 2003, c. E-5.1. The energy charge is based on the Alberta pool price for energy and is subject to change.

Applicability

1. Commercial Customers are eligible for this rate if a reasonable forecast of the customer's annual consumption of electric energy at a site is less than 250 MWh.
2. Within ENMAX Power Corporation's electric distribution limits for electricity services which are permanently metered and where the energy consumption is less than 5,000 kWh per month.

Rate

Energy Charge	$0.05437 per kWh
Administration Charge	$0.36883 per day
Energy Market Charge/Refund	As set out in this Tariff
System Access Service Charge	As per Distribution Tariff
Distribution Access Service Charge	As per Distribution Tariff

Local Access Fee (LAF)

A fee set by agreement with the City of Calgary applicable to all services located within the City of Calgary.

Billing Period

Monthly

Terms and Conditions

All services provided under this rate are subject to ENMAX Power Corporation Terms and Conditions for Regulated Rate Tariff.

This Regulated Rate Tariff will be offered to Commercial customers commencing from January 1, 2004 to December 31, 2004.

Regulated Rate Tariff
Rate Code R350 - Medium Commercial

This rate schedule is for the provision of electricity services in accordance with the *Regulated Default Supply Regulation* (168/2003) and the *Electric Utilities Act*, S.A. 2003, c. E-5.1. The energy charge is based on the Alberta pool price for energy and is subject to change.

Applicability

1. Commercial Customers are eligible for this rate if a reasonable forecast of the customer's annual consumption of electric energy at a site is less than 250 MWh.
2. Within ENMAX Power Corporation's electric distribution limits for electricity services where the energy consumption is greater than 5,000 kWh per month and a monthly peak demand of 150 kVA was not registered twice in the previous 12 months.

Rate

Energy Charge	$0.05437 per kWh
Administration Charge	$0.36883 per day
Energy Market Charge/Refund	As set out in this Tariff
System Access Service Charge	As per Distribution Tariff
Distribution Access Service Charge	As per Distribution Tariff

Local Access Fee (LAF)

A fee set by agreement with the City of Calgary applicable to all services located within the City of Calgary.

Billing Period

Monthly

Terms and Conditions

All services provided under this rate are subject to ENMAX Power Corporation Terms and Conditions for Regulated Rate Tariff.

The Regulated Rate Tariff will be offered to Commercial customers from January 1, 2004 to December 31, 2004.

SCHEDULE B – EEC RRT TERMS AND CONDITIONS

"EEC RRT T&Cs.doc"

(Consists of 24 pages)

ENMAX Power Corporation
Terms and Conditions for Regulated Rate Tariff

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TERMS AND CONDITIONS FOR REGULATED RATE TARIFF

These Terms and Conditions set forth the terms and conditions upon which ENMAX Power Corporation will provide a Regulated Rate Tariff, through ENMAX Energy Corporation, to Eligible Customers. The Regulated Rate Tariff Rate Schedule and Fee Schedule are applicable under these Terms and Conditions.

1.0 DEFINITIONS

The following words and phrases, whenever used in these Terms and Conditions or a Rate Schedule or a Fee Schedule, shall have the respective meanings set out below.

(a) **"Affiliate"** means an "affiliate" as defined in the *Business Corporations Act* R.S.A., c.B-9.

(b) **"Alberta Interconnected Electric System"** means "interconnected electric system" as defined in the EUA.

(c) **"Board"** means the Alberta Energy and Utilities Board.

(d) **"Business Day"** means a day other than a Saturday, Sunday or Statutory holiday in the Province of Alberta.

(e) **"Contract Demand"** means the Demand from a Site as outlined in these Terms and Conditions.

(f) **"Customer"** is the Person whose name appears on the bill.

(g) **"Default Supplier"** means the Person or entity appointed by EPC to sell or provide Energy and perform all functions of a Default Supplier as contemplated in the Roles, Relationships and Responsibilities Regulation made under the EUA.

(h) **"Demand"** is the Rate at which Electric Energy is delivered to or by a system, part of a system, or a piece of equipment; expressed in kilowatts, kilovolt amperes, or other suitable unit at a given instant or average over any designated period of time. The primary source of "Demand" is the power consuming equipment of the Customers.

(i) **"Distribution Access Service"** means "distribution access service" as defined in the EUA and includes services required to transport electricity to Customers by means of an electric distribution system.

(j) **"Distribution Tariff"** means the tariff under which Distribution Access Service is provided.

(k) **"Distribution System"** means "electric distribution system" as defined in the EUA.

(l) **"EEC"** means ENMAX Energy Corporation.

(m) **"Electric Energy"** has the meaning given to that term in the EUA.

(n) **"Electricity"** has the meaning given to that term in the EUA.

(o) **"Electricity Services"** means "electricity services" as defined in the EUA, and includes exchanging Electric Energy through the Alberta Power Pool, making financial arrangements to manage financial risk associated with the pool price, provision of distribution access service, system access service, system support service, Metering, information systems and other miscellaneous services.

(p) **"Eligible Customer"** means a rate classification customer and any other customer in EPC's Service Area whose annual Electric Energy consumption is forecast to be less than 250MWh.

(q) **"Energy"** means "electric energy" as defined in the EUA.

(r) **"Energy Charge"** is that portion of the charge for Electricity Services based on the Electric Energy (kWh) consumed or billed under the appropriate Rate Schedule.

(s) **"ENMAX"** means ENMAX Corporation.

(t) **"EPC"** means ENMAX Power Corporation and where applicable, EEC as owner-appointed provider of the Regulated Rate Tariff.

(u) **"EUA"** means the *Electric Utilities Act,* S.A.2003, c.E-5.1, including the regulations enacted thereunder, as re-enacted, amended, supplemented or replaced from time to time.

(v) **"Facilities"** means EPC's physical facilities including, without limitation, transmission and distribution lines, wires, transformers, meters, meter reading devices and other electrical apparatus.

(w) **"Fee Schedule"** means the schedule forming part of the Regulated Rate Tariff that sets out the additional charges that may be incurred by Customers for the provision of Electricity Services pursuant to the Regulated Rate Tariff, as amended from time to time.

(x) **"Force Majeure"** means acts of God, strikes, walkouts, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, high water, washouts, inclement weather, laws, orders, restraints or acts of courts or other public, civil or military authorities, civil disturbances, explosions, breakdown or accident or necessity of repairs to equipment or lines of the electric transmission and distribution systems, loss, diminution or impairment of electrical service from generating plants, suppliers or the systems of others with which the Distribution System is interconnected, failure of any supplier or Retailer to perform, failure, curtailment, interruption or reduction of the transmission or distribution systems' capacity and any other event or circumstance, whether of the kind herein enumerated or otherwise, not reasonably within the control of EPC; provided that in no event shall the lack of finances or inability to perform due to financial condition or similar financial predicament constitute Force Majeure.

(y) **"ISO"** means the Independent System Operator and has the meaning given to it under the EUA.

(z) **"ISO Rules"** means the Rules of the Power Pool established by the ISO from time to time pursuant to Section 20(1) of the EUA

(aa) **"Load"** means Demand.

(bb) **"Load Settlement"** has the meaning given to that term in the EUA.

(cc) **"Metering"** means the purchase, installation, operation and reading of a meter that measures and records the amount of electricity consumed by a Customer.

(dd) **"Owner"** has the meaning given to that term in the EUA.

(ee) **"Parties"** means EPC and the Customer and "**Party**" means either EPC or the Customer.

(ff) **"Person"** includes an individual, firm, partnership, association, joint venture, body corporate, corporation, trustee, executor, administrator, legal representative, or organization.

(gg) **"Power Pool"** has the meaning given to that term in the EUA.

(hh) **"Rate"** includes all rates and prices as shown in the Rate Schedule.

(ii) **"Rate Schedule"** means the schedule forming part of the Regulated Rate Tariff that sets out the charges to Customers for the provision of Electricity Services pursuant to the Regulated Rate Tariff, as amended from time to time.

(jj) **"Regulated Rate Tariff"** means the tariff comprised of these Terms and Conditions and the Rate and Fee Schedules under which electricity services are provided to Customers in accordance with the Regulated Default Supply Regulation, AR 168/2003 as amended.

(kk) **"Retail Access Services Agreement"** means an agreement between EEC and the Owner of a Distribution System which sets forth the terms upon which the Owner of a Distribution System provides Retail Access Services to EEC.

(ll) **"Retail Access Services"** means the services provided by the Owner of a Distribution System to Retailers of Electrical Energy including without limitation, Load Settlement, Metering services and Distribution Access Service.

(mm) **"Retailer"** means a "retailer", as defined in the EUA.

(nn) **"Roles, Relationships and Responsibilities Regulation"** means the Roles, Relationships and Responsibilities Regulation AR169/2003 enacted under the EUA, as re-enacted, amended, supplemented or replaced from time to time.

(oo) **"Service Areas"** means those areas where EPC has a Retail Access Services Agreement with the Wire Service Owner.

(pp) **"Service Connection"** means the physical connections of EPC Facilities to the facilities of the Customer and includes end use connections, network connections and direct transmission connections.

(qq) **"Site"** means the point of end use consumption.

(rr) **"Terms and Conditions"** means these Terms and Conditions for the Regulated Rate Tariff, as amended from time to time.

(ss) **"Wire Service Owner"** means the local distributor of electricity within a geographic area, i.e. EPC within the City of Calgary.

2.0 INTERPRETATIONS

2.1. Conflicts

If there is any conflict between a provision expressly set out in a Rate Schedule, a Fee Schedule and these Terms and Conditions, the express provision of the Rate Schedule or Fee Schedule, as the case may be, shall govern.

2.2. Headings

The division of these Terms and Conditions into sections, subsections and other subdivisions and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of these Terms and Conditions.

3.0 GENERAL PROVISIONS

3.1. Tariff

EPC furnishes Electricity Services under its Regulated Rate Tariff, which includes these Terms and Conditions, the associated Rate Schedules and a Fee Schedule. EPC has assigned all of its obligations to provide Electricity Services under the Regulated Rate Tariff to Eligible Customers to EEC. The Rates include charges for Distribution Access Service, billing and the Electric Energy consumed by the Customer. These Terms and Conditions apply to all Electricity Services provided under the Regulated Rate Tariff. Assignment of EPC's obligations to provide Electricity Services under the Regulated Rate Tariff to EEC, does not relieve EPC of its responsibility for these obligations. EPC is identified in these Terms and Conditions as the provider of all Electricity Services under the Regulated Rate Tariff to reflect its ongoing obligation and the regulated nature of the tariff. The Regulated Rate Tariff is available for public inspection during normal business hours at the business offices of EPC, has been filed with the Board for approval purposes and is also posted on the EPC website.

3.2. Effectiveness of Terms and Conditions

These Terms and Conditions form part of the Regulated Rate Tariff and have been approved by The Alberta Energy and Utilities Board. These Terms and Conditions come into force on January 1, 2004 unless otherwise indicated and will be in force until another Regulated Rate Tariff is approved.

3.3. Amendment of Regulated Rate Tariff

EPC can only amend the Regulated Default Tariff with the approval of its regulator The Alberta Energy and Utilities Board. Approved amendments will take effect after thirty (30) days notice has been given to Customers, unless otherwise ordered. When an amendment is approved, revisions will be made to the Regulated Rate Tariff, with the effective date of the amendments indicated in the revised section(s).

3.4. Acceptance of Terms and Conditions

Either the taking of Electricity Services by the Customer pursuant to the Regulated Rate Tariff or the payment by the Customer of the initial account rendered by EPC constitutes acceptance by the Customer of these Terms and Conditions and assumption of all obligations set forth herein with respect to the Regulated Rate Tariff. Before energizing any Site, EPC will inform the Customer if there are any special conditions that must be satisfied. Such conditions are specific to individual Customers and situations.

3.5. Modification of Regulated Rate Tariff

No agent or employee of EPC is authorized to modify any provision, charge, or rate contained in the Regulated Rate Tariff or to bind EPC to perform in any manner inconsistent with the Regulated Rate Tariff.

4.0 REGULATED RATE TARIFF

4.1. Provision of Regulated Rate Tariff

EPC will provide Electricity Services to Eligible Customers under the Regulated Rate Tariff in accordance with the applicable Rate Schedule and these Terms and Conditions. EPC will make reasonable efforts to provide Electricity Services, that will allow for the supply of Energy to the

Customer's facilities at a nominal 60-Hertz alternating current and at the nominal voltage level for the Service Connection and variations, which comply with the Canadian Standards Association standards. Some voltage levels may not be available at all locations served by EPC's Distribution System. EPC shall make all reasonable efforts to provide a continuous supply of Energy to its Customers, but cannot guarantee an uninterrupted supply of Energy. Interruptions may occur due to the need for EPC to operate and maintain its facilities or due to events, which are beyond EPC's control. Notwithstanding any other provision of these Terms and Conditions, should Electricity Services be interrupted by defective equipment or fail from an event or cause of Force Majeure, EPC will not be liable for the defect, irregularity, interruption or failure.

Procedural and technical requirements that must be met prior to connecting facilities to the EPC distribution system within the network boundary are described in the document entitled "Network Servicing Policies and Guidelines". Procedural and technical requirements that must be met prior to connecting facilities to the EPC Distribution System outside the network boundary are described in the document entitled "Technical Terms and Conditions for Distribution Wires Access". Both documents are posted on the EPC website.

Only the owner of the premises to be served may be the Customer of record unless a tenant provides a signed lease or other evidence demonstrating occupancy for at least a consecutive six-month period, in which case the tenant shall be the Customer of record. All Customers must be of legal age to contract for Electricity Services with EPC. EPC reserves the right to verify the identity of the Customer and the accuracy of the information provided. Customers may be required to:

Supply information relating to load, preferred supply conditions, creditworthiness and the manner in which the Electricity Services will be utilized; and

Pay deposits, fees and charges as stated in EPC's Rate and Fee Schedules and Terms and Conditions.

Upon receipt of the required information, EPC will advise the Customer of any special conditions that must be satisfied before EPC will provide any Electricity Services, the Site at which the Electricity Services will be provided, the Customer's distribution Contract Demand and, if requested, the location of EPC's metering and related equipment.

The Customer shall be responsible for obtaining all permits, certificates, licenses, inspections, reports, and other authorizations and right-of-way agreements necessary for the installation and operâtion of the Electricity Services and shall submit copies of them to EPC upon request. EPC shall not be required to commence or continue installation or provision of Electricity Services unless and until the Customer has complied with the requirements of all governmental authorities, all permits, certificates, licenses, inspections, reports and other authorizations, and all right-of-way agreements, and all EPC requirements applicable to the installation and provision of Electricity Services.

4.2. Responsibilities

4.2.1. Rights of Way

At the request of EPC, the Customer shall grant, or cause to be granted to EPC, without cost to EPC, such easements, rights-of-way and rights of entry over, upon or under the property owned, occupied or controlled by the Customer as EPC reasonably requires for the construction, installation, maintenance, repair and operation of the Facilities required for Electricity Services and the performance of all other obligations required to be performed by EPC hereunder.

The Customer shall be responsible for managing vegetation on the property owned, occupied or controlled by the Customer to maintain proper clearances and reduce the risk of contact with EPC's Facilities. At the request of the Customer and if necessary, EPC will make reasonable efforts to de-energize the Customer's Electricity Services at no cost to the Customer to allow the Customer to manage vegetation as required by this Section. If, in the opinion of EPC, the Customer has failed to adequately manage vegetation as required by this Section, EPC may at the Customer's expense perform the work that EPC determines is reasonably required. EPC shall make reasonable efforts to notify the Customer before such work is performed.

The Customer shall not install or allow to be installed on property owned or controlled by the Customer any temporary or permanent structures that could interfere with the proper and safe operation of EPC's Facilities or result in non-compliance with applicable statutes, regulations, standards and codes.

4.2.2. Payment of Invoice

The Customer receiving Electricity Services at a Site will be billed for such Electricity Services. When a change of occupancy occurs at a premises, five (5) days prior notification of such change must be given to EPC. EPC may accept a change of occupancy notification from a third party willing to accept responsibility for payment for Electricity Services at the premises. The outgoing Customer will be held responsible for all Electricity Services supplied to the premises until notice is received and accepted by EPC.

The Customer shall pay all fees, rates and charges required to be paid under these Terms and Conditions upon receipt of an invoice for the fees, rates and charges. Unless specifically provided otherwise in a Rate Schedule, or a Fee Schedule, EPC's rates are based upon the furnishing of continuing Electricity Services to the Customer's premises at a single Site. EPC will issue a separate bill for each Site. However, the Customer and EPC may agree that EPC will issue one bill totaling charges for Electricity Services delivered at more than one Site. Customers shall be invoiced for Electricity Services according to the Rate set out in the applicable Regulated Rate Tariff Schedule and invoiced in accordance with this Section. Opening and Closing bills will be prorated.

Invoices shall be deemed rendered, and other notices duly given when delivered to the Customer personally, when mailed to or left at the premises where Electricity Services are provided or the last known address of the Customer or when delivered to the address specified in Section 9.5 hereof. Failure to receive such an invoice from EPC will not entitle the Customer to any delay in the settlement of each account nor to any extension of the date after which a late payment charge becomes applicable. In the case of a dispute between EPC and the Customer, the Customer may dispute charges shown on the Customer's bill or any other matters by contacting EPC, either in writing or by telephone, and advising EPC of the reason for the dispute. If the Customer disputes any charges, the Customer must still pay the amount shown on the Customer's bill. EPC will promptly investigate all disputes and advise the Customer of the results.

Payment shall be made by way of cash, cheque or automatic debit to the office/address specified by EPC. A cheque remitted by a Customer in payment of a bill is accepted conditionally.

Any invoice rendered to a Customer for which valid payment has not been received by the due date shall be considered past due. On the first day following the payment due date, late payment charges at a rate established by EPC from time to time and specified in the invoice will be applicable to all overdue billed amounts, including arrears and previously unpaid late payment charges. Customers who fail to make payments on time for Electricity Services will also be subject to normal credit action, which may include, but is not limited to:

- Reminder letters;
- Notification by telephone;
- Use of collection agencies;
- Requiring prepayment before additional service;
- Service disconnection; and
- Legal action.

Any Customer who neglects or refuses to pay when due, all amounts required to be paid under these Terms and Conditions, the Rate Schedules and the Fee Schedule will no longer be eligible for Electric Energy pursuant to the Regulated Rate Tariff. EPC, in its sole discretion, based on the Customer's payment history and willingness to secure future payments, may choose to maintain the Customer on the Regulated Rate Tariff. However, where a Customer has its service disconnected twice in a twelve (12) month period, their Electricity Services under the Regulated Rate Tariff will be discontinued.

4.2.3. Underpayments

Underpayments of any amount are treated as normal receivables outstanding.

4.2.4. Overpayments

If the Customer pays EPC an amount in excess of what is owed to EPC, the excess amount will be carried as a credit balance on the Customer's account and applied to bills for future Electricity Services unless the Customer requests a refund.

4.2.5. Returned Cheque Fee

EPC may assess a returned cheque fee, as outlined in the Fee Schedule attached to these Terms and Conditions, to any Customer whose cheque for payment to EPC is dishonored by any bank when presented for payment by EPC. Receipt by EPC of a cheque or payment instrument that is subsequently dishonored shall not be considered valid payment.

4.2.6. Collection of Taxes

EPC shall collect all sales, excise, or other taxes imposed by governmental authorities with respect to Electricity Services under the Regulated Rate Tariff.

4.2.7. Customer Facilities

The Customer shall be responsible for the installation and condition of all equipment and facilities on the Site or on premises owned, controlled or occupied by the Customer. EPC will retain ownership of its equipment and Facilities whether affixed to a Customer's facilities or not.

4.2.8. Customer Liability

The Customer assumes full responsibility for the proper use of Electricity Services provided by EPC and for the condition, installation, suitability and safety of any and all wires, cables, devices or appurtenances on the Customer's premises or on premises owned, controlled or occupied by the Customer.

4.2.9. Protective Devices

The Customer shall be responsible for determining whether the Customer needs any devices to protect the Customer's facilities from damage that may result from the use of Electricity Services including, without limiting the generality of the foregoing, single phasing protection on three-phase Service Connections. The Customer shall provide, install, and maintain all such devices.

4.2.10. Service Calls

EPC will require a Customer to pay the appropriate fee as outlined in the Fee Schedule attached to these Terms and Conditions, for a Customer-requested service call if the source of the problem is the Customer's facilities.

4.2.11. Standards for Interconnection

The Customer's installation shall conform to the requirements of EPC's "Technical Terms and Conditions for Distribution Wires Access" and/or such further requirements as EPC may establish from time to time. Copies of such requirements are available from EPC and will be posted on the ENMAX web page.

4.2.12. Suitability of Equipment

All of the Customer's facilities shall be suitable for operation with Electricity Services and Facilities provided by EPC. The Customer shall not use Electricity Services for any purpose, or with any apparatus, that would cause a disturbance to any part of EPC's Distribution System.

4.3. Connections

4.3.1.Interruptions

EPC may discontinue or otherwise curtail, interrupt or reduce Electricity Services without liability whenever EPC reasonably determines, or when EPC is directed by the ISO , that such a discontinuation, curtailment, interruption or reduction is necessary to facilitate construction, installation, maintenance, repair, replacement or inspection of any of EPC's Facilities; to maintain the safety and reliability of EPC's Distribution System; or due to any other reason, including emergencies, forced outages, potential overloading of EPC's Distribution System or Force Majeure.

4.3.2.ISO Requirements

The Customer acknowledges and agrees that EPC is bound by all ISO operating instructions, policies and procedures as are set forth in the ISO Rules, as may be revised from time to time, which are needed to maintain the integrity of the Alberta Interconnected Electric System. The Customer acknowledges and agrees that it will cooperate with EPC so that EPC will be in compliance with all ISO procedures, which include, but are not limited to, those procedures pertaining to minimum and maximum generation emergencies, and measures requiring involuntary Customer participation, such as supply voltage reduction or full interruption of Customer Load by either manual or automatic means.

4.3.3. Compliance with Governmental Directives

The Customer acknowledges and agrees that EPC may need to act in response to governmental, regulatory or civil authority directives or orders, which may affect Customer Load and/or operations. The Customer agrees to cooperate with EPC in order to enable EPC to comply with the directives and orders.

4.3.4. Interference with EPC's Property

No one other than an authorized employee or agent of EPC shall be permitted to remove, operate, or maintain meters, electric equipment or other Facilities. The Customer shall not interfere with, extend or alter EPC's meter, seals or other Facilities or permit the same to be done by any Person other than the authorized agents or employees of EPC. EPC property shall be installed at points most convenient for EPC's access and service and in conformance with public regulations in force from time to time. The Customer shall be responsible for all destruction, loss or damage to EPC's meters, electric equipment, seals or other Facilities located on the Customer's premises or on premises owned, operated or controlled by the Customer where the destruction or damage is caused by a negligent act or omission or willful misconduct of the Customer or anyone permitted by the Customer to be on the premises, provided however, that the Customer shall not be liable for such destruction, loss or damage where such destruction, loss or damage is occasioned by circumstances beyond the Customer's control.

4.3.5. Protection of EPC's Equipment

The Customer shall furnish and maintain, at no cost to EPC, the necessary space, housing, fencing, barriers, and foundations for the protection of Facilities necessary for the provision of Electricity Services to be installed upon the Customer's premises, or on the premises owned, occupied or controlled by the Customer, whether the Facilities are furnished by the Customer or by EPC. If the Customer refuses, EPC may at its option furnish and maintain, and charge the Customer for furnishing and maintaining, the necessary protection. Such space, housing, fencing, barriers and foundations shall be in conformity with applicable laws and regulations and subject to EPC's specifications and approval.

4.3.6. Unauthorized Use or Unsafe Conditions

If EPC determines that there has been an unauthorized use of Energy or Electricity Services including but not limited to any tampering with a meter or other EPC Facilities, unauthorized connection or reconnection, or theft, fraud, intentional or unintentional use of Energy whereby EPC is denied full compensation for services provided, EPC may make such changes in EPC's meters, appliances, or other Facilities or take such other corrective action as may be appropriate to ensure only the authorized use of the Facilities and Electricity Services, and also to ensure the safety of the general public and EPC personnel and the Customer is hereby deemed to consent to such corrective action. Upon finding an unauthorized use of Facilities or Energy or finding that Electricity Services have not been used in accordance with these Terms and Conditions, EPC may discontinue the Electricity Services and charge the Customer, all damages suffered by EPC and all costs incurred in correcting the condition. Nothing in this section shall be deemed to constitute a waiver of any other rights of redress, which may be available to EPC, or to limit in any way any legal recourse, which may be open to EPC.

4.3.7.Relocation of EPC's Facilities

The costs of relocating EPC's meter, seals or other Facilities shall be borne by the Customer when done at the Customer's request, for the Customer's convenience, or if necessary to remedy any violation of law or regulation caused by the Customer. If requested by EPC, the Customer shall pay the estimated cost of the relocation in advance.

4.3.8.Customer's Facilities

The Customer will ensure that its facilities comply with the applicable requirements of the Canadian Electrical Code and with all technical guidelines issued from time to time by EPC. The Customer shall not use its Electricity Services in a manner so as to cause undue interference with any other Customer's use of Electricity Services such as an abnormal disturbance to the voltage, frequency and waveform of the Energy supply. At EPC's request, the Customer shall take whatever action is required to correct such interference or disturbance at the Customer's expense. Alternatively, EPC may elect to correct the interference or disturbance at the Customer's expense and the Customer is hereby deemed to consent to such corrective action.

A Customer shall not extend or permit the extension of its facilities connected to EPC's Distribution System beyond property owned, controlled or occupied by that Customer.

4.4. Change in Electricity Services

4.4.1.Prior Notice by Customer

A Customer shall give EPC reasonable written notice prior to any change in the Customer's requirements for Electricity Services, including any change in Contract Demand, to enable EPC to determine whether it can accommodate such change without alterations to its Facilities. Any Person who is acting as agent for a Customer and who provides verifiable authorization from the Customer may give such notice to EPC on the Customer's behalf. If EPC receives such notice from a Person, EPC may at its option require that such notice be provided directly from the Customer.

The Customer shall not change its requirement for Electricity Services without EPC's written permission. The Customer shall be responsible for all damages, whether direct or indirect or consequential, caused to EPC's Distribution System or Facilities as a result of the Customer changing its requirements for Electricity Services without EPC's permission.

4.4.2. Changes to EPC's Facilities

If EPC must modify its Facilities to accommodate a change in a Customer's requirements for Electricity Services, the Customer shall pay for all costs attributable to such modification including, without limitation, the following costs:

- the original capital cost of the Facilities being removed, less any contribution-in-aid-of-construction made to the capital cost of those Facilities, less accumulated depreciation, plus
- the estimated cost of removing the Facilities, less the estimated salvage value, plus
- the estimated cost of installing EPC's new Facilities, less
- any applicable EPC investment.

4.5. Discontinuation of Service

4.5.1. Discontinuation at Request of Customer

The Customer may at any time on thirty (30) days prior verbal or written notice to EPC, request the discontinuation of the Electricity Services. Discontinuation notice can be revoked with at least 48 hours notice in advance of the scheduled discontinuation date. The Customer may be required to pay for any unrecovered investment made by EPC in respect of providing the Customer's Electricity Services.

4.5.2. Discontinuation for Safety and System Security Reasons

EPC reserves the right, without liability, to discontinue Electricity Services to a Customer at any time without notice, or to refuse to make such Electricity Services available to the Customer, where, in EPC's opinion, any of the following conditions exist:

- the Customer has permitted the Customer's facilities to become hazardous; or
- if to EPC's knowledge or in its judgment, the Customer's facilities are unsafe or defective or will become unsafe or defective imminently; or

- the Customer's facilities fail to comply with applicable statutes, regulations, standards and codes and EPC's requirements;
- the use of Electricity Services may cause damage to EPC's Facilities or Distribution System or interfere with or otherwise disturb any other service provided by EPC; or
- the existing loads, in EPC's opinion, have characteristics that might adversely affect the quality of service supplied to other Customers, the public safety, or the safety of EPC's personnel.

EPC will resume Electricity Services when the condition has been rectified to EPC's satisfaction, when the Customer has provided, or paid EPC's costs of providing, such Facilities as may be necessary to rectify the condition and prevent the condition from reoccurring, and the Customer's facilities are approved by the appropriate authority. EPC shall make a reasonable effort to notify each Customer within a reasonable time after discontinuation, of the reason for the discontinuation and the actions required to resume the service.

4.5.3. Discontinuation Other Than for Safety Reasons

EPC may at any time, after having given at least 48 hours' prior verbal or written notice to a Customer and without any further notice, discontinue Electricity Services to the Customer under the Regulated Rate Tariff or install a current-limiting device to restrict the capability of Electricity Services if the Customer:

- violates any provision of these Terms and Conditions or EPC's Distribution Tariff (including the provision of a deposit when requested or failure to pay for the Electricity Services provided under the Regulated Rate Tariff);
- has instituted by or against it any formal or informal proceeding for the dissolution or liquidation of, settlement of claims against, or winding up of the affairs of the Customer; or
- ceases or threatens to cease to carry on business, makes or agrees to make a bulk sale of assets without complying with applicable law or commits an act of bankruptcy, or otherwise acknowledges its insolvency;
- tampers with any service conductors, seals or any other Facilities or any meters, whether or not provided by EPC;
- does not have currently in force all permits, certificates, licenses, or other authorizations or right-of-way agreements that may be required for the installation and operation of Electricity Services;

- changes its requirements for Electricity Services without the written permission of EPC; or

- provides EPC with incorrect information or makes fraudulent or unauthorized use of Electricity Services.

4.5.4. Relocation of Customer

If the Customer wishes to relocate from the Site(s) originally identified, the Customer must notify EPC at least twenty (20) Business Days prior to relocation of the address of its new location. The Customer will be responsible for any additional costs or expenses incurred by EPC in servicing alternate Sites. Should the Customer relocate in an area outside of EPC's Service Area, service will be discontinued under this Regulated Rate Tariff.

4.5.5. Restoration of Service

If Electricity Services to a Customer are restricted by a current limiting device or disconnected (other than for safety reasons and whether at the request of the Customer or not) the Customer shall pay the following amounts prior to EPC reconnecting Electricity Services:

- any amount owing to EPC;

- a reconnection charge as outlined in the Fee Schedule attached to these Terms and Conditions, if Electricity Services are restored during EPC's normal business hours, or, in any other case, an amount not exceeding EPC's actual cost of reconnection; and

- a security deposit in such amount, if any, as determined by EPC in its sole discretion as contemplated in Section 4.5.10 hereof.

Where a Customer has had its service restricted or disconnected twice in a twelve (12) month period, the Electricity Services under this Regulated Rate Tariff will be discontinued.

4.5.6. Return to the Regulated Rate Tariff

In order for a Customer to return to the Regulated Rate Tariff once service has been discontinued (other than for safety reasons or at the request of a Customer), the Customer will, in addition to complying with Section 4.5.5, be required to demonstrate being in good standing with an electricity provider for a period of twelve (12) months without going into arrears. EPC in its sole discretion may reduce this waiting period.

4.5.7. Removal of Facilities

Upon termination of Electricity Services, EPC will be entitled to enter upon and remove from the property owned, occupied or controlled by the Customer any of EPC's Facilities located upon the property.

4.5.8. Fee Schedule

EPC reserves the right to impose reasonable fees and charges pursuant to the various provisions of these Terms and Conditions and as approved by the Board. The fees and charges shall be set out in the Fee Schedule which forms part of these Terms and Conditions and may be amended from time to time.

4.5.9. Credit

The Customer agrees upon request to cooperate with EPC in establishing the Customer's creditworthiness, including the disclosure of its billing and payment history. The Customer represents to EPC that all verbal or written financial information furnished by or on behalf of the Customer to EPC is accurate and complete in every respect on the date the information is provided. The Customer consents to EPC sharing this information with EEC and credit agencies for the purpose of credit approval and with any government, regulatory or municipal authorities if required in order to provide the Electricity Services to the Customer.

4.5.10. Security Deposit

A guarantee deposit as security for payment in an amount, determined by EPC, may be required prior to or during the provision of Electricity Services pursuant to this Regulated Rate Tariff . Guarantee deposits, unless otherwise applied, will be refunded with interest to the Customer after the Customer establishes a satisfactory payment record.

A guarantee deposit will be applied by EPC against any indebtedness of the Customer to EPC. When Electricity Services are discontinued, EPC shall refund, with interest, to the Customer all or any portion of such deposit not applied previously, in accordance with EPC policy at the time of such discontinuance.

4.5.11. Default Supplier

If a Regulated Rate Tariff Customer ceases to be eligible for Electricity Services under the Regulated Rate Tariff, that Customer will, subject to compliance with the Terms and Conditions of Service of the Default Supplier, be eligible for Electricity Services from the Default Supplier.

4.5.12. Confidentiality

Subject to EPC's compliance with the EUA Code of Conduct Regulation AR 160/2003, in order for EPC to establish and maintain commercial relations with customers and to provide ongoing service; to understand customer needs and preferences; to bring its customers relevant and personalized new products, special offers and specialized customer care and to meet legal and regulatory requirements, EPC will from time to time, collect customer information and may exchange and use this customer information among its Affiliates and agents. EPC shall limit the collection of customer information to that which is necessary for the purposes identified above and shall collect such information by fair and lawful means. The customer information, except as provided herein, will not be shared with other companies or organizations.

By accepting service under the Regulated Rate Tariff, the Customer is deemed to consent to the exchange and use of its Customer information as discussed above, unless the Customer advises EPC otherwise. The Customer is not required to consent to this exchange and use of information and there are no negative consequences for a customer who does not consent except that without access to the Customer's information, it may limit EPC's ability to provide the Customer with service..

5.0 METER SERVICES

5.1. Installation of Meters

5.1.1.Provision and Ownership

EPC shall provide, install and seal one or more meters for the purpose of measuring the Energy delivered to a Customer. Each meter shall remain the sole property of EPC regardless of the degree to which the meter may be affixed to the Customer's equipment, premises, or to premises owned, occupied or controlled by the Customer or equipment.

Time of use or interval meters shall be installed for a Customer who has a Load equal to or exceeding 150 kVA at least twice in a 12-month period. For new Customers moving into existing space, EPC will make an estimate of Site Demand, and if the estimate is greater than or equal to 150 kVA, an interval meter will be installed. For an existing Site where modifications are made to the infrastructure requiring Load to be equal to or in excess of 150 kVA, an interval meter will be installed. In these cases, the costs of the new interval meter, including installation, will be borne by EPC.

5.1.2.Responsibility of Customer

Each Customer shall provide and install a meter socket or meter enclosure and other approved and required facilities suitable for the installation of EPC's meter or metering equipment in accordance with EPC's current "Technical Terms and Conditions for Distribution Wires Access" posted on the ENMAX website.

5.2. Location

Meter locations shall be designated by EPC based on the type of Electricity Services requested and convenience of access to the meter. Where a meter is installed on a Customer-owned pole, the pole shall be provided and maintained by the Customer as required by the Canadian Electric Code and any other applicable statutes, regulations, standards and codes.

5.3. Access to Metering Equipment

EPC may, at any reasonable time, read, inspect, remove and test its meter installed on property owned or controlled by the Customer. EPC's employees, agents and other representatives shall have the right to enter property owned, occupied or controlled by a Customer at all reasonable times and intervals for the purpose of installing, maintaining, replacing, testing, monitoring, reading or removing EPC's electrical equipment and appliances or other Facilities or for discontinuing service or for any other purpose incidental to the provision of Electricity Services and the Customer shall not prevent or hinder EPC's entry.

5.4. Off-Cycle Meter Read or Meter Testing

EPC will test any meter provided by EPC at the request of the Customer subject to the charges set out in the Fee Schedule, which is attached to these Terms and Conditions. If EPC determines the meter is operating outside tolerances specified by Measurement Canada, the cost of testing and replacement will be borne by EPC.

5.5. Changes to Metering

EPC may at any time change any meter it installed.

Should a Customer request that an interval meter be installed or a communication device be attached to an existing meter, the request shall be made in accordance with the provisions set out in the "Technical Terms and Conditions for Distribution Wires Access". EPC shall provide, install, test, and maintain the requested metering or communication device. The Customer shall bear the cost incurred by EPC in providing and installing the meter or attaching the communication device in accordance with the Fee Schedule. Upon installation, the meter or communication device shall remain the property of EPC and will be maintained by EPC. EPC shall complete installation of the meter or attachment of the communication device, if reasonably possible, within 30 days of receiving a request from the Customer. EPC shall invoice the Customer upon installation.

6.0 CUSTOMER GENERATION

A Customer will not directly or indirectly connect or permit the connection of any source of Energy to EPC's Distribution System unless there is an agreement in force between the Customer and EPC with respect to the connection.

7.0 LIABILITY AND INDEMNIFICATION

7.1. Definitions

7.1.1 In this Article:

7.1.1.1 "direct loss or damage" means direct physical damage, injury or loss, but does not include loss of profits, loss of revenue, loss of production, loss of earnings, loss of contract or any other indirect, special or consequential loss or damage whatsoever;

7.1.1.2 "ENMAX Power Corporation" or "EPC" includes:

7.1.1.2.1 ENMAX Power Corporation, ENMAX Energy Corporation or "EEC" (in its capacity as regulated rate provider for EPC), their affiliates, contractors, agents, authorized representatives and assigns, and the, directors officers and employees (while those employees are acting within the course and scope of their employment) of each of them; and

7.1.1.2.2 for the purposes of clause 5.1.1.2.1, "affiliate" has the meaning given to it in the *Business Corporations Act* (Alberta); and

7.1.1.3 "customer information" has the meaning given to it in the *Code of Conduct Regulation* made under the *Electric Utilities Act*, S.A. 2003, c. E-5.1.

7.2 Limitation of Liability

7.2.1 EPC does not guarantee or promise uninterrupted service. Except for direct loss or damage caused by the negligence of EPC, EPC shall not be liable to any Customer or other person in law, equity, tort or contract for any loss, damage, injury or claim of any nature whatsoever, arising out of or in any way connected with its performance under these Terms and Conditions, the provision of Electricity Services or any other services provided under these Terms and Conditions, or under EPC's Distribution Tariff and the Terms and Conditions approved as part of EPC's Distribution Tariff, or any failure, estimated data errors, defect, fluctuation, reduction, de-energization, suspension, curtailment or interruption in the provision of Electricity Services or any other services provided under these Terms and Conditions, or under EPC's

Distribution Tariff and the Terms and Conditions approved as part of EPC's Distribution Tariff.

7.3 Indemnity

7.3.1 The Customer shall indemnify and hold harmless, and at the option of EPC, defend EPC from and against all claims, actions, costs, fees (including legal fees and disbursements on an indemnity basis), judgments, fines, penalties and any liability in law, equity, tort or contract for any loss, damage, injury or claim of any nature whatsoever, brought against EPC which arise from, result from, or are in any way connected with any act, omission or failure of the Customer arising from, resulting from or in any way connected with these Terms and Conditions or EPC's Regulated Rate Tariff, under EPC's Distribution Tariff and the Terms and Conditions approved as part of EPC's Distribution Tariff, or under any other arrangement or agreement between the Customer and EPC, or between the Customer and any third party.

7.3.2 Without limiting the generality of the preceding paragraph, the Customer shall also indemnify and hold harmless, and at the option of EPC, defend EPC from and against all claims, actions, costs, fees (including legal fees and disbursements on an indemnity basis), judgments, fines, penalties and any liability in law, equity, tort or contract for any loss, damage, injury or claim of any nature whatsoever, brought against EPC by any person, which arise from, result from, or are in any way connected with:

7.3.2.1 the routine presence in or use of Energy over the wires, cables, devices or other facilities owned or controlled by the Customer;

7.3.2.2 the failure of the Customer to perform any of the Customer's duties and obligations as set out in these Terms and Conditions; or

7.3.2.3 the Customer's improper use of Energy of electric wires, cables, devices or other facilities.

7.4 Force Majeure

7.4.1 If an event or circumstance of *Force Majeure* occurs that affects EPC's ability to provide Electricity Services or any other services provided under these Terms and Conditions (the "Services"), so far as they are affected by the *Force Majeure* or its consequences, the Services shall be suspended until the *Force Majeure* or its consequences are remedied, and for such period thereafter as may reasonably be required to restore the Services. Where reasonably practical, EPC shall give advance notice to the Customer of such *Force Majeure*. It is recognized and agreed that it may not be possible for EPC to provide advance notice of such *Force Majeure*, in which case EPC shall provide the Customer with notice as soon as practicable.

7.4.2 EPC is not liable to Customers or any other person in law, equity, contract or tort for any loss, damage, injury or claim of any nature whatsoever arising from or connected in any way with: the amount or lack of notice given by EPC of an event of *Force Majeure*.

8 CONSEQUENTIAL LOSS

Neither EPC or the Customer shall be liable to the other Party for special, indirect or consequential damages resulting or arising out of performance under these Terms and Conditions, including, without limiting the generality of the foregoing, loss or damage resulting from loss of use, revenue, profit or opportunity whether or not a Party has been advised of the possibility of such loss or damage.

9 MISCELLANEOUS

9.1 Compliance with Applicable Legal Authorities

EPC and the Customer are subject to, and shall comply with, all existing or future applicable federal, provincial and local laws, and all existing or future orders or other actions of the ISO or governmental authorities having applicable jurisdiction. EPC will not violate, directly or indirectly, or become a party to a violation of any requirement of any applicable federal, provincial or local statute, regulation, bylaw, rule or order in order to provide Electricity Services. EPC's obligation to provide Electricity Services is subject to the condition that all requisite governmental and regulatory approvals for the provision of Electricity Services have been obtained and will be maintained in force during such period of service.

9.2 No Waiver

The failure of either Party to insist in any one or more instances upon strict performance of any provisions of these Terms and Conditions, or to take advantage of any of its rights hereunder, shall not be construed as a waiver of any such provisions or the relinquishment of any such right or any other right hereunder, which shall remain in full force and effect. No term or condition of these Terms and Conditions shall be deemed to have been waived and no breach excused unless such waiver or consent to excuse is in writing and signed by the Party claimed to have waived or consented to excuse.

9.3 Law

These Terms and Conditions shall be governed by the laws of the Province of Alberta and the federal laws of Canada applicable in the Province of Alberta, without regard to principles of conflicts of law. Any lawsuit arising in connection with these Terms and Conditions shall be brought in the courts of the Province of Alberta.

9.4 Legislative Amendments

EPC reserves the right to terminate any service under the Regulated Rate Tariff upon the happening of any change or amendment to applicable laws, tariffs, rules, regulations or procedures (or the application or implementation of same).

9.5 Notices

Unless otherwise stated herein, all notices, demands or requests required or permitted under these Terms and Conditions shall be in writing and shall be personally delivered, mailed or sent by facsimile transmission (with the original transmitted by any of the other aforementioned delivery methods) addressed as follows:

- If to the Customer: to the address and the addressee on record with EPC
- If to EPC regarding service changes or installations:

ENMAX Power Corporation
141 – 50th Avenue SE
Calgary, Alberta
T2G 4S7

Phone Number: (403) 514-2807
Fax Number: (403) 514-2975

and:

If to EEC regarding billing, credit, or customer information:

ENMAX Energy Corporation
141 – 50th Avenue S.E.
Calgary, Alberta
T2G 4S7
Phone Number: (403) 310-2010
Fax Number: (403) 514-2165 or (403) 514-2166

A Party may change the address or addressee from time to time by giving written notice of such change to the other Party in accordance with this section. Any notice, demand or request made, given or delivered hereunder is considered delivered; when sent by facsimile, on the next Business Day following a confirmed facsimile; when mailed, at the end of the fourth (4th) Business Day after mailing; when hand delivered, at the time of delivery where proof of delivery date is provided.

SCHEDULE C – EEC RRT FEE SCHEDULE

"RRT Fee
Schedule.doc"

(Consists of 3 pages)

2004 REGULATED RATE TARIFF

FEE SCHEDULE – JANUARY 1 TO DECEMBER 31, 2004

The fees and charges contained in this schedule are non-refundable and are charged in all circumstances. These fees apply to Customer required services as described in the Regulated Rate Tariff Terms and Conditions.

1. New Connection: **$• per request**

This EPC DT fee applies to a request for a new service connection.

2. Application **$10.00 per request**

This fee applies when a Customer requests a new service.

3. Temporary De-energize: **$• per request**

This EPC DT fee applies to a request for a temporary de-energization of service.

4. Re-energize after Temporary De-energize: **$• per request**

This EPC DT fee applies to a request for a re-energization of service.

5. Permanent De-energize: **No charge**

This EPC DT service applies to sites where the site is de-energized and the equipment permanently removed.

6. Meter Field *in situ* Test: **$• for Self-Contained Meter**
$• for Instrument-Type Meter

This EPC DT fee applies when the Meter Shop tests a meter at the request of a Customer. The fee is charged only if the accuracy of the meter is found to be within the limits allowed by the Government of Canada.

7. Interval Data Request – 15 minute, DIM Format: **$• per site per request**

This EPC DT fee applies to a request for interval meter data for the previous 12 months or less from date of request.

8. Interval Data Request – Other than 15 minute, DIM Format: **$• per site per request**

This EPC DT fee applies to a request for interval meter data for the previous 12 months or less from date of request.

9. Interval Data Report or Graph: $• per site per request

This EPC DT fee applies to a request for a Report or Graph (available from MV-90) for the previous 12 months or less from date of request.

10. Interval Data – All other Requests: $• per hour

This EPC DT hourly fee applies to a request for services that are not listed in the Fee Schedule.

11. Cumulative Data Request, DCM Format: $• per site per request

This EPC DT fee applies to a request for cumulative meter data for the previous 12 months or less from date of request.

12. Cumulative Data – All Other Requests: $• per hour

This EPC DT hourly fee applies to a request for services that are not listed in the Fee Schedule.

13. Data Request Requiring Data File in Excel or "PRN." Format: $• per site per request

This EPC DT fee applies to a request for meter data in Excel or "PRN." file format for the previous 12 months or less from date of request.

14. Customer Requests – Off-Hours: $• per hour

This EPC DT fee applies to a request for work to be done after Customer business hours to minimize disruption of their business, which requires an EPC crew working on overtime hours.

15. Dishonoured Cheques: $25.00 per cheque

This fee applies to all dishonoured cheques returned to EEC for any reason.

16. Security Deposit: Special – per customer merit

A security deposit may be requested from a Customer, or the Customer's credit history may be accepted.

17. Meter Verification/Certification: $• per hour plus materials

This EPG DT fee applies to a request for verification or certification of a meter. In the event that the meter is faulty, the fee is waived.

18. Meter Upgrade: **$• per hour for one person/one truck (single phase)**
$• per hour for two people/one truck (multi phase)

This fee is applicable for the time associated with meter upgrades. The Customer is also responsible for the cost of the materials, including the meter.

19. Penalty for Late Payment: **3.25% of the outstanding balance**

This fee applies when remittance is past the due date. A one-time penalty charge of 3.25% will be applied to the outstanding invoice thirty (30) days after written notice has been given.

20. Final Notice: **$15.00 Per notice**

Applied to a Customer account when the account is over 60 days in arrears and a final letter of notice has been issued.

18. Meter Upgrade: **$• per hour for one person/one truck (single phase)**
$• per hour for two people/one truck (multi phase)

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